Arnold Schwarzenegger
Governor

Improving Interconnections in California: THE FOCUS II PROJECT

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program
Energy Systems Integration

Prepared By:
Reflective Energies
Overdomain LLC
Endecon Engineering

JANUARY 2005
CEC-500-2005-006

Prepared By:
Reflective Energies
Edan Prabhu
Mission Viejo CA

Overdomain LLC
Cris Cooley
Santa Barbara CA

Endecon Engineering
Chuck Whitaker
San Ramon CA

Contract No. 500-00-013

Prepared For:
California Energy Commission
Public Interest Energy Research (PIER) Program

Dave Michel
Contract Manager

Laurie ten Hope
Program Area Team Lead
PIER Energy Systems Division

Ron Kukulka,
Acting Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Robert L. Therkelsen
Executive Director

ACKNOWLEDGEMENTS

The FOCUS-II Interconnection team, (Reflective Energies, Endecon Engineering, Overdomain) wishes to thank the parties that participated in this project. Our deepest thanks and appreciation go to Scott Tomashefsky, who has led the Interconnection Working Group through more than 50 meetings, four Rule 21 advice letter filings, and the countless thorny brambles that dot the landscape of any public forum—especially one that seeks consensus, as the Rule 21 group does. Scott has managed to lead the group to consensus on every major issue it has encountered. We appreciate the wisdom and patience of Dave Michel, Mark Rawson, Bill Junker and Laurie ten Hope. We thank Werner Blumer and Valerie Beck of the California Public Utilities Commission (CPUC)—Werner for his dogged, meticulous and indefatigable commentary on all substantive Rule 21 documents and Valerie for her work in helping to turn advice letters into CPUC-adopted rule language. We also thank SCE, PG&E, SDG&E, Capstone, and the City of Riverside for their hospitality in hosting Rule 21 meetings. Finally, we thank the participants who come to the Rule 21 working group meetings, including:

Anthony Mazy – CPUC/ORA
Bill Cook – SDG&E
Bill Erdman – DUA
Bill Martini - Tecogen, Inc.
Bill Steeley – EPRI
Bob Panora – Tecogen
Bryan Fox – Capstone
Chris Frye - Alternative Energy Inc.
Chris Wirth – EMC
Chuck Arthur - Arthur Eng
Chuck Collins - DER—DOE
Chuck Solt – Lindh
Chuck Sorter - BluePoint Energy
Dan Tunnicliff – SCE
Dara Salour RCM Digesters
Dave Redding – Riverside Public Utilities
Debbie Rodgers – SCE
Denise Canning SCE
Dixon Yee - PG&E
Ed Grebel – SCE
Ed Quiroz - CPUC/ORA
George Couts SCE
Gerome Torribio – SCE
Greg Ball - Powerlight
Herb Clowers - Hess Microgen
Jeff Goh - PG&E
Jerry Jackson - PG&E
Jim Ross - CAC/EPUC
Jim Skeen - SMUD
John Horak - Basler Electric
Jose Cervantes - City of San Diego
Joseph Heinzmann - General Electric
Karl Iliev - SDG&E
Kent Sheldon - SMA-America Inc.
Leon Woods – Worldwater
Manuel Alvarez – SCE
Michael Edds - Edds Consulting
Mike Iammarino – SDG&E
Mike Mazur - 3 Phases Energy Services
Mohammad Vaziri - PG&E
Nora Sheriff – EPUC/CAC
Pat Aldridge - SCE
Paul Della - PacifiCorp
Paul Fukumoto - Ingersoll-Rand Energy Systems
Paul Samson - RealEnergy
Peter Ouborg - PG&E
Petrina Burnham - SDG&E
Robert Patrick - Valley Air Solutions
Robin Luke – RealEnergy
Scott Lacy – SCE
Scott Steffer - Modesto Irrigation District
Susan Gardner - Redhawk Energy Consultants
Tim Boucher – SCE
Tim O'Toole – INC
Tom Bialek - SDG&E
Tom Blair - City of San Diego
Tom Dossey – SCE
Tracy Saville - TK & Company

PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration.

This is the final report for the **FOCUS–Interconnection II, Contract Number 500-00-013,** conducted by Prime Contractor Reflective Energies and Subcontractors Overdomain and Endecon Engineering. Power Measurement supplied monitoring equipment. This report is entitled **Improving Interconnection in California: The FOCUS-II Project.** This project was sponsored by the California Energy Commission PIER **Energy Systems Integration** program area.

For more information on the PIER Program, please visit the Commission's Web site at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.

ABSTRACT

Improving Interconnection in California:

The FOCUS-II Project

Forging a Consensus on Interconnection

Final Report

500-00-013

The FOCUS-II project (Forging Consensus on Utility System Interconnection-II) was funded by the California Energy Commission (Energy Commission) with Public Interest Energy Research (PIER) Strategic Energy program funds. It consists of two primary Project activities: 1) Monitoring the impact of fourteen selected Distributed Generation (DG) systems on the distribution system and 2) Streamlining Rule 21 through supporting the Energy Commission run a Working Group that resolves technical and process challenges related to interconnection. The Rule 21 Working Group included all major stakeholders in DG—California investor-owned utilities, municipal utilities, DG manufactures, suppliers, advocates, developers and users, the CPUC and others. The meetings used a collaborative, consensus-building approach to make interconnection faster, less costly, more uniform between California utilities, and better integrated with national standards, such as IEEE P1547—the national interconnection technical standard. The products of the effort include an Interconnection Monitoring Report, a revised, improved Rule 21, a California Interconnection Guidebook, a Supplemental Review Guide, a DG Interconnection System Certification process, and an Interconnection Cost Effectiveness Report.

Key Words: Distributed Generation, DG, Interconnection, Rule 21, Rule 21 Certification, Power Quality, PQ.

TABLE OF CONTENTS

ABSTRACT .... **III**

EXECUTIVE SUMMARY **1**

1 INTRODUCTION **5**

1.1 BACKGROUND AND OVERVIEW 5

1.2 PROJECT OBJECTIVES 8

1.3 REPORT ORGANIZATION 8

2 PROJECT APPROACH **9**

2.1 DEVELOP CERTIFICATION DATABASE SPECIFICATIONS 9

2.1.1 Specification Requirements 9

2.1.2 Specification Approaches 9

2.2 MONITORING GRID AND POWER QUALITY IMPACTS OF COMMERCIAL DG 11

2.2.1 Objectives 11

2.2.2 Sites Included & Locations 13

2.2.3 Computing Infrastructure 15

2.2.4 Root Mean Square (RMS) Voltage Variations 16

2.2.5 Voltage Harmonic Distortion 18

2.3 STREAMLINING RULE 21 21

2.3.1 The Working Group 21

2.3.2 Creating and Implementing the Testing and Certification Process 21

2.3.3 The Concept of Initial Review and Supplemental Review 22

2.3.4 Cost Effectiveness Study Approach 27

2.4 THE CALIFORNIA INTERCONNECTION GUIDEBOOK 36

2.4.1 Introduction 36

2.4.2 Interconnection Application and Approval 39

2.4.3 Technical Requirements and Certified Equipment 39

2.4.4 How to Apply for Interconnection 39

2.4.5 Electric Utility Review 41

2.4.6 Interconnection Agreements 42

2.4.7 Installation and Commissioning 43

2.4.8 Problem and Dispute Resolution 43

2.5 FOCUS SUPPORT FOR IEEE ACTIVITIES 43
2.5.1 IEEE 1547 and its Impacts on Rule 21 44
2.5.2 UL 1741/IEEE P1547.1 and their Impact on Rule 21 46
2.5.3 FERC Small Gen ANOPR and its potential Impact on Rule 21 47
3 PROJECT OUTCOME 49
3.1 DEVELOP CERTIFICATION DATABASE SPECIFICATIONS 49
3.1.1 Specifications for a Certification Database 49
3.1.2 Specifications for a DG Database 51
3.1.3 Specification for an Electronic Application 51
3.2 MONITORING GRID AND POWER QUALITY OUTCOME 52
3.2.1 SARFI: Sag and Interruption Rates 53
3.2.2 Monitoring SARFI Rates 53
3.2.3 SARFI Rates by Month 54
3.2.4 Event Aggregation 56
3.2.5 Statistics of Voltage Total Harmonic Distortion 57
3.3 RULE 21 WORKING GROUP SUPPORT 59
3.3.1 Rule 21 Working Group Administrative Support 59
3.3.2 FOCUS-II Cost Effectiveness Outcome 61
3.3.3 Process Improvement Objective 61
3.3.4 Time Reduction Objective 68
4 CONCLUSIONS AND RECOMMENDATIONS 79
4.1 CONCLUSIONS 79
4.1.1 Specification Conclusions 79
4.1.2 Monitoring Project Conclusions 79
4.1.3 Streamlining Rule 21 Conclusions 82
4.2 CONCLUSIONS AND RECOMMENDATIONS 85
APPENDIX A: LINKS TO FOCUS-II INTERCONNECTION REPORTS .... A
ATTACHMENT A: WEBSITES AND REFERENCES .... B

TABLE OF FIGURES

Figure 1-1:Interconnecting DER on the Distribution System 6
Figure 2-1: FOCUS-II Computing Infrastructure 16
Figure 2-2: The Initial Review Process 23
Figure 3-1: Specification for Electronic Contract 52
Figure 3-2: SARFI Rates by Month 55
Figure 3-3: Simplified Interconnection Progress 67
Figure 3-4: All Utilities Initial & Supplemental Interconnections vs. Baseline 67
Figure 3-5: PG&E Annual Progress 69
Figure 3-6: SCE Annual Progress 69
Figure 3-7: SDG&E Annual Progress 69
Figure 3-8: California Annual Progress 70
Figure 4-1: Typical Daily Load Profile for San Diego NGIC 81
Figure 4-2: Time Delay Trendline (All CA IOUs) vs Baseline Units <1MW 82
Figure 4-3: Time Delay Trendline (All CA IOUs) vs Baseline Units 1MW+ 82
Figure 4-4: Projected Savings from revised Rule 21 84

TABLE OF TABLES

Table 2-1: Utility/Municipality Site Distribution 13
Table 2-2: FOCUS-II Monitoring Sites by Technology and Utility 14
Table 2-3: Customer type distribution 15
Table 2-4: Sample from a "CaIS" Interconnection Status Report 25
Table 2-5: "Making Connections" Ten-Point Action Plan 30
Table 2-6: California Interconnection Time Delays 32
Table 2-7: Carrying Costs for various DER Technologies and Sizes 34
Table 2-8: Hours Assumed for Operating Modes 35
Table 3-1: Specification for Certification Database 50
Table 3-2: Specification for Distributed Generation Database 51

TABLE 3-3: AVERAGE EVENTS PER YEAR BY SARFI TYPE – ALL MONITORS 54
TABLE 3-4: TEMPORAL AGGREGATION (TA) OF ANNUAL SARFI INDICES 56
TABLE 3-5: TOTAL HARMONIC DISTORTION SUMMARY 58
TABLE 3-6: FULFILLING THE PROCESS IMPROVEMENT OBJECTIVE 62
TABLE 3-7: ESTIMATED TRENDLINE INTERCONNECTION COSTS 72
TABLE 4-1: SUMMARY OF TRENDLINE END-USER COST SAVINGS... 83

EXECUTIVE SUMMARY

Improving Interconnection in California: The FOCUS-II Project

This Project, known as FOCUS-II, was sponsored by the California Energy Commission PIER Energy Systems Integration Program to assist in improving the interconnection of Distributed Generation (DG) to the utility distribution system in California.

FOCUS-II is a follow-on to the FOCUS-I Project, "Forging a Consensus on Utility System Integration". FOCUS-II was intended to achieve the following:

- Obtain the first-ever real data of the impact of selected commercially installed DG on the grid and the impact of the grid on DG by installing power quality monitors at the utility-DG interfaces. Evaluate the data and make recommendations as appropriate;
- Help to simplify and streamline the interconnection of DG, improve the review process, help certify systems for interconnection, assist with the integration of the national interconnection standard, IEEE 1547. Provide technical and logistical support to the Rule 21 Working Group led by the Energy Commission as it tackles difficult issues between developers, customers and utilities;
- Prepare an Interconnection Guidebook to provide DG developers and first-timers with an introduction to DG interconnection, help them better understand the complexities involved and lead them through the chain of documents and agreements necessary for achieving interconnection;
- Perform a cost-benefit evaluation of the efforts led by the Energy Commission to reduce the time and costs of interconnection in California.

The DG Monitoring Program

Utilities divide their power delivery systems into two broad categories: transmission systems at high voltages (generally above 66KV) and distribution systems at lower voltages. Most utility and Independent Power Producer (IPP) generators are connected to the high voltage *transmission* system, which is designed for two-way flow, with protections against problems between the generator and the transmission system. However, most utility customers are connected to the medium and low voltage *distribution* system; distribution systems are generally designed for one-way flow of power, with the presumption that customers will not generate power that is delivered back to the utility. The onset of DG changes this situation. Power from DG must either be consumed locally or delivered to the grid, creating two-way flow of power.

Utilities were not prepared for the advent of DG, and there was no information available on how DG would interface with the grid. This DG monitoring program is a first step in developing such information. It obtains real-time data from commercially installed DG systems, monitoring the impact of DG on the grid and vice versa. It is a very small study, monitoring just a handful of systems, but it is a start. It is hoped that other similar studies will be undertaken, and the cumulative results of these studies will provide a better picture of DG-grid interface behavior.

A parallel effort sponsored by the Energy Commission, known as the Distributed Utility Integration Test ("DUIT") Program is testing, in a laboratory setting, the electrical implications of deep and diverse penetration of DG into distribution systems. These two Energy Commission efforts will help DG stakeholders better understand the grid impact of DG, and lead to safer, more reliable, and more cost-effective means of interconnecting DG.

It was decided to monitor the most diverse and complex systems relative to grid interaction. A set of selection criteria and a test plan were developed, reviewed by the Energy Commission and the Interconnection Rule 21 Working Group, and implemented. A total of eleven DG systems monitored included one PV system, five microturbines, two fuel cell and three IC engines, with a variety of interconnection systems from solid state to synchronous generators, spread over seven locations, two in the Bay Area and five in Southern California. Five of the interconnections are to Investor-Owned Utilities (IOUs), and one to a municipal utility. One of the systems exported small amounts of power. In addition, under construction are monitors of five more DG systems (Three PV and two IC engines with induction generators) at two locations.

The data gathered represent a total of over two hundred and thirty thousand cumulative hours of monitoring. Monitors were able to measure voltage fluctuations that were less than 1/15,000 of a second in duration, and able to determine whether each unusual event was initiated by the grid or the DG. The power quality parameters measured included voltage, frequency, waveform distortion, harmonics, flicker and more. The results showed that for the systems being monitored, there was very little impact between the DG and the grid. The power quality at all sites was far better than earlier the power quality benchmarks established by EPRI and SCE within the last decade. This does not mean that the DG improved power quality. Rather, grid power quality at the points measured was better than the benchmarks, and the DG did not make it better or worse. There were no instances of DG impacting the grid during the entire monitoring effort. The only instance where the grid impacted DG was a lightning strike that damaged a fuel cell.

While the results are encouraging, the sample is small and the level of DG penetration is also small. At this time, DG is moving slowly into the marketplace, and the learning experience, though painful, is keeping pace with the growth and market penetration. The study is being expanded under FOCUS-III, and will seek more complex systems and a longer monitoring period. It is hoped that other studies will be undertaken to create a much larger database and higher confidence levels.

The Monitoring Report is included as a link in Appendix A, available through the Energy Commission website.

Streamlining Interconnections in California

The effort to streamline interconnections in California was led by the Energy Commission, with support from the FOCUS team. The Energy Commission leadership and the desire for collaborative resolution of tough issues produced valuable results. The Rule 21 Working Group was formed, comprised of stakeholders interested in interconnection of DG (utilities, regulators, DG suppliers, DG developers and others). The effort was broadly divided into three areas:

- Obtain consensus among major stakeholders on the technical and administrative issues related to interconnection;
- Revise Rule 21 and its related documents: the Rule 21 text, applications, and agreements to simplify applications, review, approval and testing of interconnection;
- Establish a process to certify systems that meet the essential requirements established for interconnection of DG.

While working to achieve the above goals, the Working Group became a forum for stakeholders to bring in their concerns related to specific interconnections or aspects of the process that were not previously considered. Utilities streamlined their organizations to speed up interconnection handling and review processes, offered training to their own staff, and conducted seminars to educate developers on how best to go about obtaining approval for interconnection. The stakeholders talked to one another, sharing challenges and success stories. This improved dialog probably helped as much as the technical improvements.

> *The average time from application to interconnection dropped from an average of 300 days to an average of less than 75 days between 1998 and 2003, and continues to drop. This is happening even while DG installations have been growing in number and complexity.*

The FOCUS team prepared a report in early 2004 titled, “Making Better Connections”. It is included as a link in Appendix A, and is available through the Energy Commission website. The report evaluates these gains and the cost-effectiveness of the FOCUS effort. The cumulative value of the realized savings from streamlining interconnection in 2001 through 2003 is more than $34 million, which compares favorably to a project cost of $1,500,000.

During the time that the FOCUS work was happening, the IEEE was developing a national standard for DG interconnection, number IEEE 1547. In order to stay abreast of what was happening at the national level, the FOCUS team provided technical support to the Working Committee for IEEE 1547. IEEE 1547 was adopted, but focused mainly on technical issues. Rule 21 covers many other issues, such as applications, processing, approvals, and perhaps most significantly, an analysis of the potential impact of the DG on the grid. There were some differences between certain technical parameters established by Rule 21 and those subsequently adopted by IEEE 1547. The Working Group is currently evaluating the differences to make the two documents compatible.

The California Interconnection Guidebook

The FOCUS team prepared a California Interconnection Guidebook that is available online at the Energy Commission website (see Appendix A: Links to FOCUS-II Interconnection Reports). The Guidebook demystifies the interconnection process for those who may find it daunting, and provides links to useful contacts, information, and documents.

Future Work: FOCUS-III

The FOCUS-II work is now being continued under another contract known as FOCUS-III. FOCUS-III will expand the monitoring program to include additional sites, continue the certification of DG, and facilitate further streamlining of interconnection.

Conclusions and Recommendations

This project, along with the efforts of many others, has helped streamline interconnections significantly. As one measure of success, the time frame for interconnections has dropped significantly even as DG applications are on the rise.

The collaborative consensus-building approach through the Working Group has helped improve communication, resolve technical issues, and has resulted in a greater appreciation by stakeholders of each other's problems.

DG is becoming more complex—driven by high prices for energy, a need for more reliable energy, energy dependency issues, a desire for clean and renewable energy, and waste disposal issues. There is a continuing need for collaborative resolution of thorny issues. It is recommended that the Working Group continue meeting, perhaps less frequently as the incidence of new issues declines.

California stakeholders should continue to work with the IEEE to keep communications open and cross-fertilize.

The monitoring program found no significant impact of DG, and only one instance of an impact of the grid on DG, caused by a lightning strike. It is recommended that the DG monitoring program be enlarged to monitor more complex sites, and the duration of the monitoring be expanded. It is recommended that other DG monitoring efforts be undertaken. FOCUS-III will begin this effort.

The project has been worth pursuing. The payback is already large, and promises to be even larger.

1 Introduction

1.1 Background and Overview

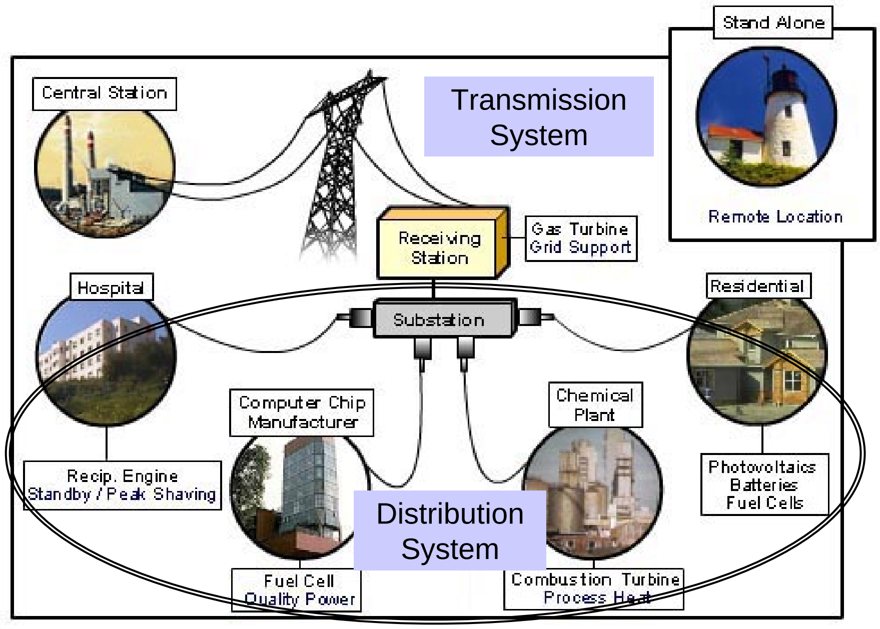
Recent events in California are causing legislators, regulators, and participants in energy markets to look beyond the traditional sources of electricity supply and delivery for answers to the state's current and future energy needs. There is increasing interest in Distributed Energy Resources (DERs) as a key to diverse, reliable, secure, and affordable electricity services. The interest is driven by many concurrent realities, including:

- Volatile natural gas prices;
- The California energy crisis and subsequent demise of electricity restructuring;
- Advances in DER technologies;
- Aging electricity transmission and distribution infrastructure;
- Incentives for renewable and clean DER generation;
- Recent capacity shortages and transmission constraint problems;
- Potential lower cost and higher service reliability of DERs;
- Improved power quality and increased energy efficiency of DERs;
- Desire for energy independence and security;
- Volatile wholesale electricity prices;
- High electricity retail prices as utilities attempt to recoup their wholesale losses;
- Advances in national and international electricity standards (such as IEEE P1547 and IEC 61850);
- Advances in control capability due to the continuing revolution in microprocessors;
- Expanded communications made possible by the Internet and associated technologies.

As stated by the California Energy Commission:[1]

> It is generally accepted that centralized electric power plants will remain the major source of electric power supply for the near future. DER, however, can complement central power by providing incremental capacity to the utility grid or to an end user. Installing DER at or near the end user can also in some cases benefit the electric utility by avoiding or reducing the cost of transmission and distribution system upgrades.

FIGURE 1-1:INTERCONNECTING DER ON THE DISTRIBUTION SYSTEM



As Figure 1-1 demonstrates, most DER must still interconnect to the grid. Although the Figure shows a "stand alone" generator isolated from the grid, this arrangement is very uncommon. Most DERs still interconnect because their owners judge that the incremental benefit of self-serving all the on-site load all the time, instead of most of the load most of the time, does not justify the incremental cost of doing so. As long as facilities with DER rely on power from the distribution system to serve supplemental load, interconnection will be key to a successful DER marketplace.

For these reasons, the Energy Commission began to search for ways to accelerate proliferation of DER, and specifically Distributed Generation (DG), when it issued the Order Instituting Investigation (OII) November 3, 1999 to identify barriers to the development of DG technologies and to develop recommendations to remove those barriers. The Commission accepted the task of developing rules and bringing its recommendations to the California Public Utilities Commission (CPUC) for discussion and possible adoption. Under the OII, the Commission was to explore barriers to DG in the areas of Interconnection and permit streamlining. The FOCUS technical support contract that is the subject of this report was signed to help the Commission fulfill its OII obligations.

---

[1] Quote and (modified) graphic are from: http://www.energy.ca.gov/distgen/background/background.html

In its early work (called FOCUS-I, Contract Number 700–99–010), the FOCUS team successfully completed 14 interconnection objectives:[2]

- Objective-1: Facilitate consensus on the technical issues of Interconnection.
- Objective-2: Make Interconnection a single uniform process that is internally consistent and predictable statewide.
- Objective-3: Provide a method of Simplified Interconnection.
- Objective-4: Explore the role of advanced communications and metering for interconnection scheduling and dispatch.
- Objective-5: Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs).
- Objective-6: Lower the cost of Interconnection.
- Objective-7: Fulfill the need for interim standards.
- Objective-8: Address safety issues.
- Objective-9: Define the scope and feasibility of Type Testing.
- Objective-10: Accelerate the adoption of DG by training and informing government agencies.
- Objective-11: Define the scope of technologies covered by Rule 21.
- Objective-12: Make changes to utility tariffs proceeding from Interconnection rules.
- Objective-13: Facilitate Interconnection of small units.
- Objective-14: Eliminate utility discretion of study fees.

Key CPUC interconnection decisions stemming from this work include D.00-11-001: Interim Decision Adopting Interconnection Standards (November, 2000) and D.00-12-037: CPUC Decision Adopting Interconnection Standards (December 2000). These Decisions took the recommendations of the Interconnection working group and adopted them with virtually no changes.

DG in California progressed, but still had a long way to go. For example, at the conclusion of the FOCUS-I contract there were no Certified DG units, though the new Rule 21 outlined the Certification process; IEEE 1547 was still underdevelopment and had not been incorporated into the new Rule; no clarification existed for Supplemental Review; despite the efforts of the working group, when the three utilities filed their tariff letters, they lacked uniformity; there was a need for standard interconnection agreements; it was not clear whether interconnection applications were progressing faster than they did prior to the Rule 21 revision. There were still outstanding issues needing technical and administrative support from the Energy Commission.

The Energy Commission wanted to assess what value revisions to Rule 21 had delivered.

---

[2] "Forging A Consensus On Interconnection Requirements In California (FOCUS)", Onsite Sycom, February 2001, p1, http://pier.saic.com/PDF/P600-01-006.pdf.

DG was becoming a reality with interconnection rules in place, but there was no data available on how the DG impacted the distribution system. Although several other notable power quality studies had been done, no field study showing the nature of the DG/grid interaction yet existed. Utility engineers were familiar with large generating units and had definitive studies on their mutual impacts at the high voltage transmission level, but they had no information on how DG would impact the grid at the medium and low voltage distribution level. Besides, the distribution system was not designed to consider future addition of DG at the tail end of the line.

The FOCUS-II Project was set up to provide answers to these questions.

1.2 Project Objectives

The Energy Commission set out five objectives for the FOCUS team—one covered by the Monitoring study and four by the Cost Effectiveness study:

- Characterize the electrical effects of DG on the distribution system (Supported by the Monitoring Study);
- Evaluate whether Revised Rule 21 has improved the process of interconnection of DG to the electrical system (Supported by the Cost Effectiveness study);
- Assess the potential for simplifying Rule 21 further to expand the types of different applications eligible for a "simplified interconnection" and thus improve the cost-effectiveness of interconnection; (Supported by the Cost Effectiveness study.)
- Reduce the cost of interconnection below what was experienced prior to the Revised Rule 21 by 30% for units less than one megawatt and by 15% for units equal to or greater than 1MW; (Supported by the Cost Effectiveness study.)
- Reduce the costs associated with delays in approval and installation of interconnection by more than 20% for projects less than 1MW. (Supported by the Cost Effectiveness study.)

This Final Report will discuss each of these objectives in detail, including an assessment of the degree to which they've been met.

1.3 Report Organization

Section 2 of this report covers Project Approach, providing summaries of documents prepared in support of the Rule 21 working group effort, and giving an account of the hypotheses, analytical approaches, and technological set up necessary to carry out the project tasks.

Section 3 covers the Project Outcome, giving the results of working group support, results for the produced by each task.

Section 4 covers Conclusions and Recommendations for all work in the FOCUS-II Interconnection program.

2 Project Approach

Each item in the FOCUS-II scope of work is calculated to remove interconnection as a barrier to DG. This section describes the particular interconnection issues at hand and the approach taken to mitigate or resolve the issues. Section 2.1 covers Certification Database Specifications; Section 2.2 covers Monitoring Grid and Power Quality Impacts of Commercial DG; Section 2.3 covers Streamlining Rule 21; Section 2.4 covers the California Interconnection Guidebook; Section 2.5 covers FOCUS Support for IEEE Activities.

2.1 Develop Certification Database Specifications

2.1.1 Specification Requirements

The FOCUS-II contract required that the FOCUS team prepare the following specifications:

1. A certification database of all devices certified for interconnection in California;
2. A database of all new installed distributed generation units;
3. Specifications for electronic documents assisting in interconnection application, including:
    a. An electronic application form;
    b. An electronic interconnection help system;
    c. An electronic contract form.

Actual development, population and operation of the databases and electronic application were not in the scope of the FOCUS-II work; our task was to design the data matrix (or schema) to be developed by others.

2.1.2 Specification Approaches

Specification for Certification Database

For the specification is to divide the specification into two table-style matrices: one for certified equipment, and one for Nationally Recognized Testing Laboratories (NRTLs). The table for certified equipment specifies the field name, the units of measurement (if any), the field data type, the Rule 21 reference (if any), and descriptive comments explaining the meaning of the information to be contained in the field. The fields (elements/sub-elements) necessary for complete description of the certified equipment are:

1. **Header information** (Manufacturer, Model, Description);
2. **Ratings** (Real Power, Reactive Power, Voltage, Current, Short Circuit Current, In-rush Current, and Power Factor (PF));
3. **Trip Points** (Factory Set, Fast Under Voltage, Fast Under Voltage Timing, Under Voltage, Under Voltage Timing, Over Voltage, Over Voltage Timing, Fast Over Voltage, Fast Over Voltage Timing, Under Frequency, Under Frequency Timing, Over Frequency, Over Frequency Timing);
4. **Additional Certifications** (Non-Islanding, Non-Export);

5. **Certification Administration Information** (Effective Date, Effective Serial Number, Software Version);
6. **Test Standards** (Test Number, Title, Revision, Date);
7. **Test Laboratory.**

The NRTL table specifies field name, data type, and comments. The fields necessary for complete description of the certified equipment are:

1. **Laboratory Name;**
2. **Contact Name;**
3. **Address;**
4. **City;**
5. **State;**
6. **Zip Code;**
8. **Phone Number;**
9. **Fax;**
10. **URL;**
11. **Accreditation** (Accredited by, Accreditation Standard, Effective Date, Expiration Date).

Specification for Distributed Generation Database

The DG database was designed to closely approximate the structure of the information that was requested by the Energy Commission from SCE, PG&E, and SDG&E as part of their participation in the Interconnection Working Group. Each field in the database was to be assigned a name, the data type, a fixed width, and an acceptable value (if any). Fields necessary for description include:

1. **Interconnection Number;**
2. **Customer Type;**
3. **Location;**
4. **kW;**
5. **Technology;**
6. **Interconnection Type;**
7. **Operating Mode**
8. **Application Received;**
9. **Requested Online Date;**
10. **Contract Execution Date;**
11. **Online Date;** and

12. **Status.**

Specification for Electronic Application

Specifications for the electronic application are in three parts:

1. An electronic application form;
2. An electronic interconnection help system; and
3. An electronic contract form.

The electronic application form and electronic help system were envisioned to work together as part of an online application for interconnection. Because signing the interconnection contract is the last step prior to utility approval, the electronic contract was seen as part of a system of electronic application for interconnection. As with the DG database above, the FOCUS-II team did not want to stray from document models that had been developed by the Working Group. For this reason, it was decided that to the extent possible the electronic application should look and feel like the paper application. The purpose of the electronic version was two simplify and streamline the application process, making it less expensive and time-consuming. No new fields were developed beyond what was in the original paper application. The electronic contract, too, was modeled after the paper version. The primary difference is that the electronic version distinguishes between utility-provided information and customer provided information; and it distinguishes between both of these and the " boilerplate" contract language.

Results of these specification designs are presented in Section 3.1.

2.2 Monitoring Grid and Power Quality Impacts of Commercial DG

2.2.1 Objectives

The primary objective of the FOCUS-II Monitoring Project is to "characterize the electrical effects of DG on the distribution system".[3] The limited resources allowed for only a small sample of distributed generators to be monitored for impact. The Monitoring Project Final Report documents the results of the work. Additional sites will be monitored and monitoring of existing sites will be extended under FOCUS-III.

The Monitoring Project is the first data that specifically evaluates the impacts at the interface between DG and the distribution system. Following careful site and equipment selection, high-speed real-time monitors were installed for collecting, analyzing, and reporting power quality data at the interaction between DG and the distribution system. A total of 11 distributed generators were monitored, at 6 sites. Over 230,000 hours of real-time data were collected, with samples as frequent of fifteen-thousandth of a second (256 sample per cycle). Construction is under way to add monitors to five more DG systems at two more sites.

There are six main objectives for Task 2.2. Of these the first two were covered by the DG Guidelines. The Test Plan and its execution cover the balance. The Guidelines establish the program goals and requirements. It provides the outline for how the sites and monitoring

[3] Contract 500-00-013

instrumentation were selected. The Test Plan provides the testing details, including instrumentation, measurements to be taken, and design of the database containing the measurement data. This Final Report covers fulfillment of these secondary project objectives and contains the final analysis of the data.

1. Select of the monitoring sites, attempting to cover as the most complex sites, as many interconnection technologies, distribution system types, utilities as feasible.
2. Select a monitoring, communication and data management system.
3. Develop a Test Plan.
4. Install monitors.
5. Monitor the data and create a database for analysis of the data.
6. Analyze the data for impact of the DG on the grid and vice versa.

For each site, one monitor was installed at the service entrance (known as the "Point of Common Coupling" or "PCC"); an additional monitor was installed at the DG. The monitors obtain steady state and transient event data. Analysis of steady state and transient data provides the means to benchmark the DG and distribution interface by capturing the system's power quality performance. These two monitors together allow determination of which power quality problems originate on distribution system and which can be attributed to the DG.

The data collected by the power quality monitors in the field is transmitted to Reflective Energies master web server via the Internet. One computer allocated for the project is dedicated to downloading data from the power quality monitors in real time. Data is stored on a multi-gigabyte hard drive and backed up on an Iomega remote hard drive. The data is accessed at the master computer directly or via the intranet by address the website (dgmonitors.com).

The monitor chosen for the project was the ION 7600 or ION 8500 High Visibility Energy and Power Quality Meter manufactured by Power Measurement, Ltd. The monitor collects both triggered and sampled measurements from four voltage and four current channels. Triggered measurements provide the transient data while the sampled data provides the steady state data required to benchmark the DG/Distribution interface.

The FOCUS-II monitoring project requires that it "include at least one project with each electric investor-owned utility and one municipal utility, if available". Additionally, the FOCUS-II project requires that the monitoring program "include items such as a balance between DG technologies, interconnection technologies, technical complexity … and estimated cost of monitoring."

2.2.2 Sites Included & Locations

The site selection was developed as part of the Monitoring Program Guidelines.

Utility Sites Selected for Monitoring

The site selection was based on the size in MW of the Utility/Municipality customer load. Based on that process, the following tables summarize the sites selected. Monitors for two more sites with five more DGs are under construction.

TABLE 2-1: UTILITY/MUNICIPALITY SITE DISTRIBUTION

Site Distribution		
Utility/Municipalities	**No. of Sites**	**No. of DG**
LADWP	1	4
PG&E	1	1
SCE	3	4
SDG&E	1	2
Total	6	11

DG Technology Distribution

The technology selection was based on the types of DG that applications were made and summarized by the Utilities/Municipality and presented at the Rule 21 Working Group meetings. Based on that process, the following tables summarize the sites selected.

TABLE 2-2: FOCUS-II MONITORING SITES BY TECHNOLOGY AND UTILITY

DG Technology Distribution

DG Technology	No. of Sites	Utility/ Municipality	Status
Fuel Cell (FC)	**2**	LADWP (1)*	Survey 6/12/02 Survey 2/25/03 Install 03/26/03 & 4/23/03 Operational 6/23/03
		SCE (1)	Survey 6/27/02 Install 9/8/02 Operational 9/8/02
Natural Gas Internal Combustion Engines (abbreviated NGIC or IC)	**2**	PG&E (1)	Survey 7/30/02 PCC Installed11/14/02 NGIC Installed4/28/03 Operational 4/29/03
		SDG&E (1)	Survey 8/13/02, Install 1/20/03 Operational 2/11/03
Microturbine (abbreviated MT or NGMT)	**2**	LADWP (1) [4]	Survey 6/12/02 & 2/25/03 Install 03/26/03 & 4/23/03 Operational 6/23/03
Microturbine (2)		SCE (1)	Survey 7/02/02 Install 8/26/02 MGMT installation Started 6/1/04 Forecast Operational January 2005
Photovoltaic (PV)	**2**	SCE (1)	Survey 7/08/02 Install 9/10/02 Operational 9/10/02
		SFPUC (3) [5]	Survey 6/14/04 Install – Pending Operational - Pending

[4] LADWP – One site with two technologies (FC & NGMT)

[5] SFPUC – One site with three PV Systems

Site Locations and Details

TABLE 2-3: CUSTOMER TYPE DISTRIBUTION

Customer Type					
DG Technology (Utility/Municipality)	**Location**	**Size (kW)**	**Technology**	**IC Type**	**OP Mode**
Convenience Store					
SCE	South Gate	14	PV (BP HI Performance Thin Film PV)	P	PS
Commercial Building					
LADWP	Los Angeles	120 300	NGMT (Capstone 2-C30 & 1-C60) FC (Fuel Cell Energy DFC 300)	P	PS
SCE	Irvine	200	FC (UTC 1-PC25)	P	PS
SDG&E	San Diego	400	NGIC (Hess 200 Microgen)	P	PS/Cogen
SFPUC (future)	San Francisco	675	Power Light Solar Electric System (244 kW, 225 kW & 207 kW)	P	PS
Manufacturing					
PG&E	Sunnyvale	3000	NGIC (Waukesha - 16VAT27GL)	P	PS
Medical					
SCE	Redlands	120	NGMT (Capstone 2-C60)	P	PS/Cogen

Technology Key: NGMT = Natural Gas Microturbine, NGIC = Natural Gas Internal Combustion, PV = Photovoltaic,

Interconnection (I/C) Type Key: P = Parallel, MP = Momentary Parallel, I = Isolated

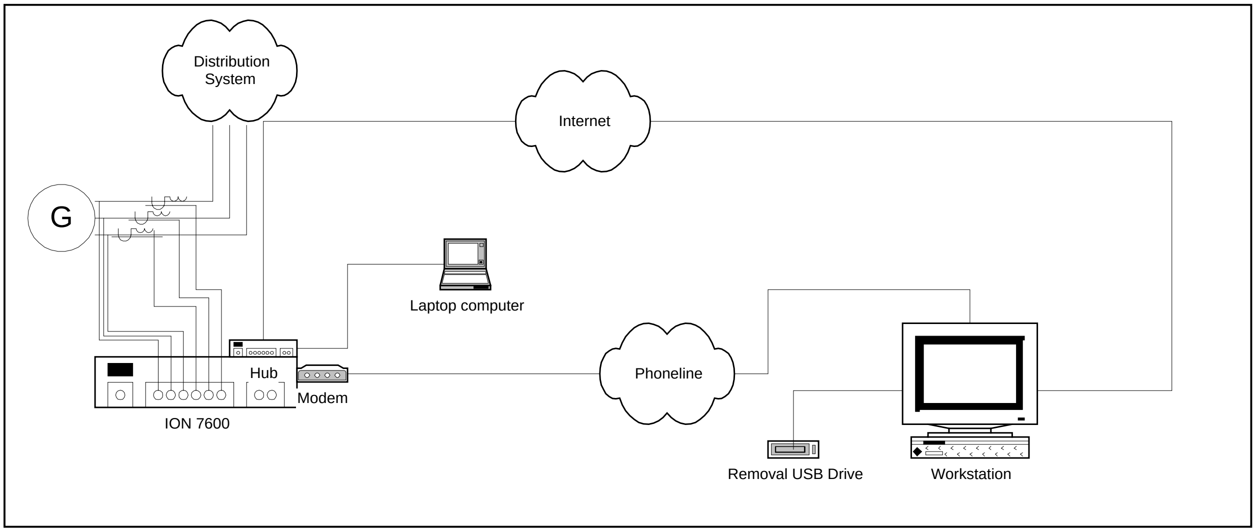
Operating (OP) Mode Key: Cogen = Cogeneration, PS = Peak Shaving

2.2.3 Computing Infrastructure

A single computer (**Dell Precision™ Workstations 530)** is dedicated to the monitoring system, as illustrated in Figure 2-1. This is a 1.7 GHz Duel Pentium IV CPU computer configured with Microsoft Windows 2000 Professional and 1.5 GB of memory. It is capable of downloading measurements from the all monitors in the field on continuous bases. It can interface with each site to monitor status and view data and then use for reporting. This workstation downloads the data from the ION 7600 and ION 8500 at the same time hosting the website (dgmonitors.com).

The database that is generated by this process is also used for report creation, data reduction and analysis.

FIGURE 2-1: FOCUS-II COMPUTING INFRASTRUCTURE



For this project the domain name dgmonitors.com was obtained and a website was developed. The website consists of two parts:

- Program overview and status, and
- Access to real time data from the monitors using Power Measurement's ION Enterprise Software Version 4.5[6].

2.2.4 Root Mean Square (RMS) Voltage Variations

2.2.4.1 RMS Voltage Variations

Voltage sags and interruptions are phenomena categorized by IEEE Std.1159-1995 as "RMS voltage variations". They are often the most important power quality concerns for customers. In general, customers understand that interruptions cannot be completely prevented on the power system. However, they are often less tolerant when their equipment fails or otherwise misoperates due to momentary disturbances that can be much more frequent than complete outages. These conditions are characterized by short-duration changes in the RMS voltage magnitude supplied to the customer. The impact on the customer depends on the voltage magnitude during the disturbance, the duration of the disturbance, and the sensitivity of the end-use equipment.

[6] For more information, visit the ION Enterprise Software product page http://www.pwrm.com/products/IONEnterprise.features/.

Voltage sags and interruptions are inevitable on the power system and are generally caused by faults on the utility system. Since it is impossible to completely eliminate the occurrence of faults, customers should decide how to protect voltage-sensitive loads from voltage variations. Storms are the most frequent causes of faults in most areas of the country. A storm passing through an area could result in dozens of major and minor power quality variations. On the utility system, protection schemes are designed to limit damage caused by unusual events such as faults caused by lightning strikes, and to localize the impact of such events to the smallest number of customers. This is often accomplished with overcurrent protection devices, such as reclosers, sectionalizers, and fuses. Voltage sags are frequently characterized by the magnitude of the voltage during the fault and the duration of the event.

$SARFI_x$

If we consider just the incidents in which the minimum voltage fell below 0.90 per unit (called 0.9pu, meaning 90% of normal system voltage) and temporally aggregate them in a 60-second period, then we can compute an index known as $SARFI_{90}$.[7] This index is a special case of $SARFI_x$. $SARFI_x$ represents the average number of specified rms variation measurement events that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than X for sags or a magnitude greater than X for swells. $SARFI_x$ only includes IEEE Std. 1159-1995 short duration measurements (i.e., less than 60 seconds in duration).

$$SARFI_x = \frac{\sum N_i}{N_T}$$

where

$x \equiv$ rms voltage threshold; with values - 140, 120, 110, 90, 80, 70, 50, and 10

$N_i \equiv$ number of customers experiencing short-duration voltage deviations with magnitudes above X% for X >100 or below X% for X <100 due to measurement event *I*

$N_T \equiv$ number of customers served from the section of the system to be assessed

Voltage regulation in North America varies from state to state and utility to utility. The national Standard in the U.S.A. is ANSI C84.1 voltage regulation requirements are defined in two categories:

- Range A is for normal conditions and the required regulation is +/- 5% on a 120 volt base at the service entrance
- Range B is for short duration or unusual conditions. The allowable range for this condition is -8.3% to 5.8%.

[7] System Average RMS (Variation) Frequency Index.

Based on the Range B requirements, the monitors for this study were set for 88% (sag trigger) and 106% (swell trigger). For this reason, in addition to measuring voltage sags with $SARFI_{90}$, in this paper we measure voltage swells outside of the normal utility range with $SARFI_{100}$ to capture the swell events between 106% and 110%.

Note that the calculation of the SARFI index is not complete unless the number of customers impacted by the depressed voltage is known. That information is outside the scope of this project. We would have had to perform some sort of our power quality state estimation to determine the voltage sag experienced by customers throughout the systems we were monitoring. Without the added information provided by state estimation, the assessed system must be segmented so that every point in the system is contained within a section monitored by an actual power quality measuring instrument. Thus, the number of monitoring locations within the assessed system becomes the number of constant voltage segments upon which the indices are calculated. Because this process of monitor-limited segmentation (MLS) results in only a few segments per circuit, the calculated index values are less accurate than those calculated using state estimation concepts. Nonetheless, MLS still yields indices that are informative.

2.2.5 Voltage Harmonic Distortion

A fundamental objective of electric utility operations is to supply each customer with a constant sinusoidal voltage. The voltage signal at any point within the power system is ideally a constant sinusoidal signal that repeats at a rate of precisely 60 times per second. Although not perfect, the voltage signal produced by power system generators approximates a perfect sinusoid with a high degree of accuracy. Almost all load equipment connected to the electric power system has been designed to operate from a sinusoidal voltage source.

Harmonic distortion of the distribution system voltage originates with nonlinear devices on the power system. Nonlinear devices produce non-sinusoidal current waveforms when energized with a sinusoidal voltage. Examples of these devices include adjustable-speed drives (ASDs), switching power supplies (including computers and other office equipment), electronic ballasts in fluorescent lighting, battery chargers, saturated transformers, and arc furnaces. Nearly all of these are nonlinear and are shunt elements, and the majority shunt devices are loads.

Harmonic distortion problems range in severity from nuisance tripping of customer end-use equipment to complete failure of very expensive utility and customer equipment. For most customers, distribution system harmonic distortion levels are generally constrained within acceptable limits, such that neither customer processes nor utility equipment are affected. Most power systems can absorb far more harmonic current than engineers might think. A large percentage of the problems occur when capacitors cause the system to be in resonance condition, thereby increasing the voltage distortion levels. Effects of harmonic distortion include heating in rotating machinery, failure of capacitor banks, telephone interference, and increased losses in system equipment.

Harmonic Distortion Assessment Indices

EPRI has developed several harmonic distortion indices to aid in the assessment of service quality for a specified circuit. The indices were defined such that they may be applied to systems of varying size. For example, the indices may be applied to measurements recorded across a utility’s entire distribution system resulting in system averages, or the indices may be applied to a smaller segment of the distribution system, such as a single feeder or a single customer PCC.

A system index value serves as a metric only and is not intended as an exact representation of the quality of service provided to each individual customer served from the assessed system. However, system index values can be used as a benchmark against which index values for various parts of the distribution system can be compared.

System Total Harmonic Distortion (STHD95) represents the 95th percentile (CP95) value of a weighted distribution of the individual circuit segment THD distribution CP95 values. Consider a distribution of THD samples collected over a monitoring period for each circuit segment comprising the assessed system. A CP95 value can be calculated for each of the individual circuit segment THD distributions. Collectively, these CP95 THD values of these individual circuit segments comprise a system distribution of segment THD CP95 values. STHD95 is the CP95 of this system segment distribution.

System Average Total Harmonic Distortion (SATHD) is based on the mean value of the distribution of voltage THD measurements recorded for each circuit segment rather than the CP95 value. SATHD represents the weighted average voltage THD experienced over the monitoring period normalized by the total connected kVA served from the assessed system.

Harmonic distortion may or may not create a problem for a facility. A customer may have harmonics present, but experience no adverse effects. However, as harmonic levels increase, the likelihood of experiencing problems also increases. Typical problems include:

- Malfunctioning of microprocessor-based equipment;
- Overheating in neutral conductors. transformers, induction motors or rotating machinery;
- Deterioration or failure of power factor correction capacitors or capacitor banks;
- Erratic operation of breakers and relays;
- Pronounced magnetic fields near transformers and switchgear;
- Telephone interference.

To make matters worse, harmonics can sometimes be transmitted from one facility back through the utility's equipment to neighboring businesses, especially if they share a common transformer. This means harmonics generated in a facility can stress utility equipment or cause problems in a neighbor's facility and vice versa. Electric utilities have recognized this problem and are adopting standards, like the Institute of Electrical and Electronics Engineers (IEEE) Standard 519 which defines allowable harmonic distortion at customer service entrances. This standard is designed to protect both businesses and utilities.

Harmonic distortion of the distribution system voltage originates with nonlinear devices on the power system. Nonlinear devices produce non-sinusoidal current waveforms when energized with a sinusoidal voltage. Examples of these devices include adjustable-speed drives (ASDs), switching power supplies (including computers and other office equipment), fluorescent lighting, battery chargers, saturated transformers, and arc furnaces. Nearly all of these are nonlinear and are shunt elements, the bulk of which are loads.

Harmonic distortion problems range in severity from nuisance tripping of customer end-use equipment to complete failure of very expensive utility and customer equipment. Fortunately, distribution system harmonic distortion levels are generally constrained within acceptable limits, such that neither customer processes nor utility equipment are affected.

Most power systems can absorb far more harmonic current than engineers might think. A large percentage of the problems occur when capacitors cause the system to be in resonance condition, thereby increasing the voltage distortion levels.

Harmonics have existed on electric power systems for many years. Recently, however, much more attention has been given to monitoring and analyzing the presence and effects of harmonics on utility and customer devices than in the past. This new concern is the result of significant increases in harmonic distortion on many electric power systems in the last fifteen to twenty years. Two factors contributing greatly to this trend are:

- **The increasing size and application of nonlinear equipment,** which produces the majority of harmonic distortion on distribution systems. Power electronic devices comprise a large part of this increase in nonlinear equipment. The percentage of electric power that passes through these devices is increasing because of the additional energy efficiencies and flexibility that they offer.
- **Increased application of utility and industrial capacitors** to increase the utilization of existing distribution system infrastructures. Utilities are installing an ever-increasing number of capacitors on transmission and distribution systems for voltage control and loss reduction. Additionally, utilities are encouraging customers, through their rate structures, to install power factor correction capacitors in order to obtain additional capacity from the existing distribution system equipment.

IEEE Std. 519-1992 provides a recommended practice for controlling harmonics on the power system. This standard divides the responsibility for controlling harmonics between the customers that have nonlinear loads generating harmonics, and the supplying utility that may have system characteristics that magnify the harmonics due to resonance. Customers need to limit the amount of harmonic current that is injected onto the utility system. Utilities need to make sure that the overall system voltage distortion is acceptable so that connected utility and customer equipment will not be impacted. The harmonic distortion levels measured in this project are compared with the recommended levels from IEEE Std. 519-1992 for reference.

To "characterize the electrical effects of DG on the distribution system", the FOCUS-II Monitoring Project uses these power quality indices:

- $SARFI_{10}$
- $SARFI_{50}$
- $SARFI_{70}$
- $SARFI_{80}$
- $SARFI_{90}$
- $SARFI_{100}$
- $STHD_{95}$
- $STHD_{99}$
- SATHD

The outcome is presented in Section 3.2 of this paper.

2.3 Streamlining Rule 21

2.3.1 The Working Group

From August 2001 through April 2004, the Rule 21 interconnection working group met 36 times.[8] The objectives of these meetings were to:

- Revise the Application form (paper version);
- Create standard Interconnection Agreements;
- Build and deploy an Electronic Application form;
- Certify DG units to facilitate Simplified Interconnection;
- Craft consensus Rule 21 language to allow all three investor-owned utilities to file uniform tariff letters;
- Encourage municipal utilities to file interconnection rules based on Rule 21;
- Revise and/or extend Rule 21 Section F (Metering) Sunset date;
- Clarify the process of Supplemental Review;
- Incorporate P1547 into Rule 21 when it became the national interconnection Standard.

Outcomes of these objectives are shown in Section 3.1.

2.3.2 Creating and Implementing the Testing and Certification Process

At the completion of the original FOCUS-I contract, the Final Siting Committee Report included, as appendices B and C (Sections I and J in the approved IOU rules), comprehensive certification process and test procedures. These procedures evaluate the suitability of interconnection equipment and establish consistent acceptance criteria among the State's utilities. This process is a major achievement since, historically, each utility set its own testing standards and requirements—often doing its own testing. There has been little attempt to harmonize the requirements or share results among utilities. Agreeing to a common set of test and certification requirements and allowing for third-party testing moved the interconnection process in California towards the goal of nationally standardized interconnection requirements. Certification is designed to facilitate a simplified interconnection under the Initial Review Process (see Figure 2-2).

The Rule 21 certification process borrowed heavily from existing standards, primarily Underwriters Laboratories 1741 *Inverters, Converters, and Controllers for Independent Power Systems* and IEEE P1547 *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems* (under development at the time), added ideas from New York and Texas certification processes, and provided some test procedures of its own, where none existed. The process was put in to practice when Capstone Energy offered its models 330 and C60 inverter-based microturbines for Rule 21 certification. The units had been Listed by UL to 1741, so,

[8] Meeting minutes may be found at http://www.energy.ca.gov/distgen/interconnection/work_group.html. No minutes were taken at several of the meetings of the technical working group.

ostensibly, it was only necessary to perform an additional Surge Withstand Test submit all of the results and have the committee review and approve the certification request.

Rule 21 Working Group leader Scott Tomashefsky of the Energy Commission set up certification verification committee (including Chairman Tomashefsky, representatives from each of the three IOUs, FOCUS team member Endecon, and others as necessary) to review and approve certification requests. The group does not certify equipment; it reviews results from tests performed by an accredited testing laboratory to determine if the Rule 21 certification requirements have been met.

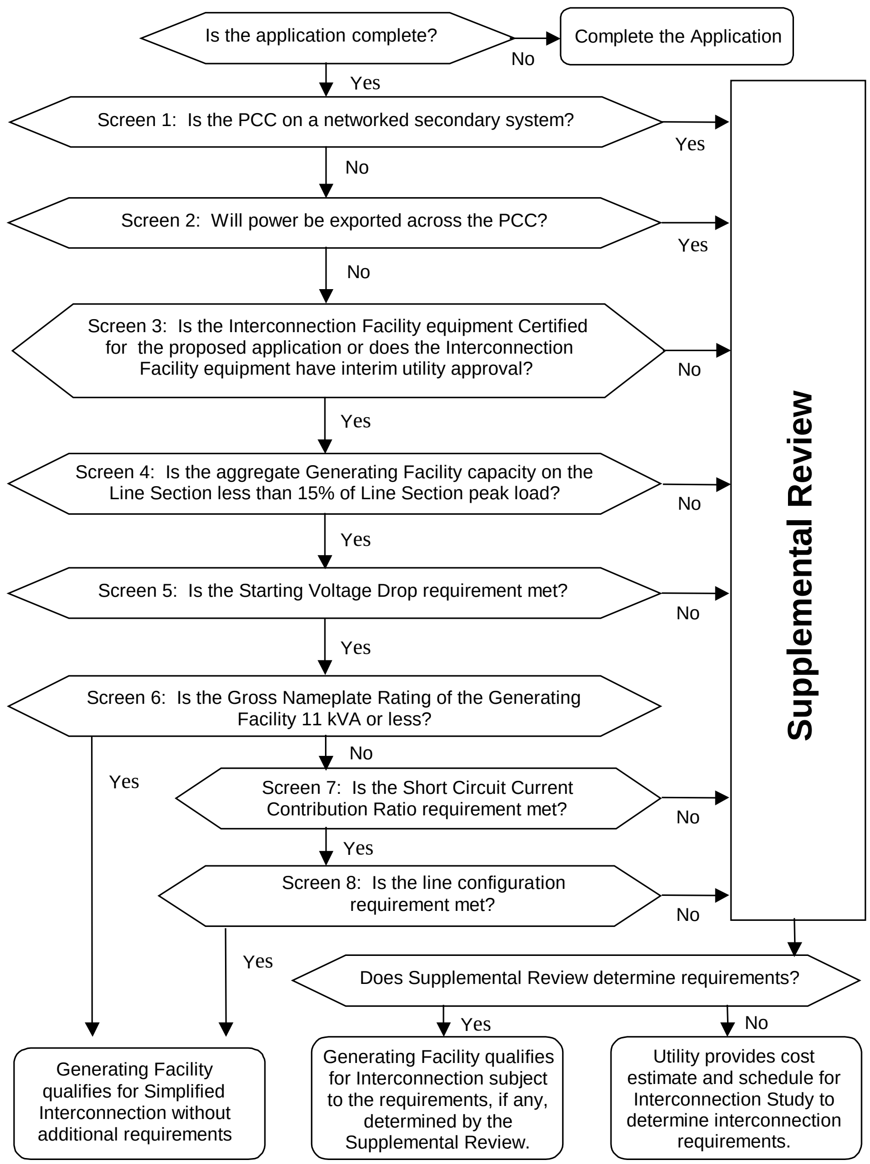
Over a period of more than 6 months, the verification committee worked with Capstone and UL to obtain the necessary information. This proved a bit more difficult than originally expected and pointed out the need to standardize the test report content and format. Since any qualified laboratory can do testing and because, by design, the test results will be used for more than just Rule 21 certification, it is difficult to require each laboratory to provide test details in a single Rule 21 format. The committee has undertaken the challenge to better understand how the results are currently being provided. The format and presentation of these results varies from lab to lab and from device to device even within the same lab. In addition, the FOCUS team has increased its involvement in national standards activities, having been invited to participate on the UL 1741 Standards Technical Panel, IEEE P1547 writing committee, and IEEE P1547.1 *Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems* (the latter as Vice Chair). These standards coordination activities ensure that the lessons learned in California are brought to the national stage to influence the content of those standards, and leverage the work of the national committees back into Rule 21 and its certification process. This activity helps ensure consistency between the California and national processes, making the eventual adoption of the national standards much more straightforward for California.

Subsequent to the Capstone certification application, Plug Power, Fuel Cell Energy, and Tecogen applied. The Certification process continues. Currently, the committee is considering a synchronous generator controller from Hess Microgen, once again establishing new boundaries in certification for utility interconnection. Results of these certification requests appear in Section 3.3.1.2.

2.3.3 The Concept of Initial Review and Supplemental Review

In assessing markets for their products, DG manufacturers saw that interconnection was a major barrier to a mass market. They wanted standardized requirements to reduce the cost and complexity of interconnecting their electricity generating equipment. The idea was to create a path of least resistance through the utility interconnection review process for units meeting pre-approved (and preferably national) certification standards and for applications where the impact of such systems would be negligible. Initial Review was the path created to define low impact applications that could bypass costly and time-consuming unit-by-unit approval without jeopardizing the safety or reliability of distribution system. It was designed to evaluate key characteristics of the DG equipment and the distribution system at the proposed location through a series of screens—a simplified interconnection study. Each screen addresses a specific issue that can signal a need for additional information. For example, certified equipment has known characteristics that do not need to be further evaluated. Together, the screens define the range of issues of concern to utility engineers. Failing any screen directs the engineer to investigate impacts of the DG on the distribution system. Supplemental Review provides the engineer the opportunity to look at those parameters identified in Initial Review to determine one of three possibilities: 1) that no additional requirements are needed, 2) that specific requirements must be met to allow interconnection, or 3) that a more detailed interconnection study is necessary. Initial Review is one of the primary contributions of Rule 21 to interconnection requirements nationally. Steps in the utility review process are discussed in greater detail in Section 2.4.5.

FIGURE 2-2: THE INITIAL REVIEW PROCESS



Utility Interconnection Status Reports for Rule 21 Applications

Since the commencement of the FOCUS-II Project, the Energy Commission asked the three IOUs whether as a courtesy to the working group they could provide interconnection status reports to track the progress of interconnection applications under the Revised Rule 21. By the end of 2001, all three IOU's were providing these reports, referred to here as California Interconnection Status Reports ("CaIS reports").[9] This data, available to all stakeholders, consists of information gathered by each utility on interconnection activity in its own territory. Besides providing the working group with information from the field on interconnection progress, the CaIS reports became essential for determining cost-effectiveness. CaIS Reports contain information on all distribution-level interconnections in the IOU territories—except Net Energy Metering (NEM) projects. Data are collected monthly since April of 2001. Because of the CaIS reports, time-to-interconnect is well documented, including both absolute and relative delay information. No absolute or relative interconnection costs are disclosed, however. Table 2-4 shows a sample report excerpt, followed by explanations of abbreviations used in the Operating Mode, Technologies, and Status columns. Date Received refers to the date when the utility receives interconnection application; Requested On-Line refers to the date that the applicant would like to interconnect.

[9] Summaries of CaIS Reports may be found at: http://www.energy.ca.gov/distgen/interconnection/rule21_stats.html

TABLE 2-4: SAMPLE FROM A "CAIS" INTERCONNECTION STATUS REPORT

Project Name	City	Gross kW	Date Rec'd	Requested On-Line	Operating Mode	Technology	Contract Execution	Status
Medical Center	Redlands	240	07/23/01	08/01/01	Cogen	NGMT	05/30/03	4
Medical Center	Rancho Mirage	4900	03/11/02	12/01/02	Cogen	NGIC	05/30/03	4
Manufacturing	Chino	70	08/13/02	09/04/02	PS	NGMT	02/18/03	4
Manufacturing	Garden Grove	1250	10/15/01	11/01/01	Standby	DIC		3
Hotel	Culver City	160	01/31/02	06/01/03	Cogen	NGIC		3
Wastewater Treatment	Orogrand	1395	09/03/02	05/01/02	PS	NGIC		3
Resort/Spa	Ojai	440	09/16/02	01/01/03	Cogen	NGIC		3
Commercial Bldg.	Lake Forest	150	10/10/02	01/31/03	Cogen	NGIC		3
Wastewater Treatment	Santa Paula	70	03/14/03	06/01/03	PP	MMT		3
Manufacturing	Covina	1063	03/14/03	06/15/03	Cogen	NGIC		3
Commercial Bldg.	Newport Beach	60	03/18/03	03/31/03	Cogen	NGMT		3
Medical Center	Newport Beach	1475	09/12/01	10/01/04	Cogen	NGIC		2
Manufacturing	Victorville	2858	03/21/01	04/15/01	PS	DIC		1
Dairy	Visalia	107	04/30/02	06/10/02	PP	MIC		1
	Total kW	**68,380**						

Operating Mode

Standby – Emergency or Backup Generator
Cogen – Cogeneration
PS – Peak Shaving
PP – Primary Power

Technologies

NGMT – Natural Gas Microturbine
NGIC – Natural Gas Internal Combustion Engine
DIC – Diesel Internal Combustion Engine
MIC – Methane Internal Combustion Engine
MMT – Methane Microturbine

Status

1 – Application received. Engineering review in progress

2 – Review complete.

3 – Contract to customer. Awaiting response

4 – Contract signed. Awaiting field inspection

5 – Interconnection approved. Released for operation

S – Application suspended – awaiting further direction from customer

W – Application withdrawn

2.3.4 Cost Effectiveness Study Approach

The purpose of the Cost Effectiveness study was to measure the value of the work being performed by the California Energy Commission to improve the process of interconnecting DG to the electric distribution system in California. The term "cost effectiveness" is used to refer to progress toward the specific objectives of the Focus II contract: the Process Improvement Objective, the Simplified Interconnection Objective, the Time Reduction Objective, and the Cost Reduction Objective, as described below.

Objectives

Progress toward these Objectives, to the extent it could be ascertained from the data at hand, is treated as the sole method of determining cost effectiveness.

1. Process Improvement Objective

   Evaluate whether Revised Rule 21 has improved the process of interconnection of DG to the electrical system;[10]

2. Simplified Interconnection Objective

   Assess the potential for simplifying Rule 21 further to expand the types of different applications eligible for a "Simplified Interconnection" and thus improve the cost-effectiveness of interconnection;

3. Time Reduction Objective

   Reduce the average time associated with approval and installation of interconnection by more than 20 percent for projects less than 1 MW;

4. Cost Reduction Objective[11]

   Reduce the cost of interconnection below what was experienced prior to the Revised Rule 21 by 30 percent for units less than 1 MW and by 15 percent for units equal to or greater than 1 MW.

---

[10] Interpreted to apply only to the distribution system.

[11] This study did not include any customer surveys on total interconnection costs, either before or after the Revised Rule 21, because that data was not available in sufficient quantity or quality at the time this report was written. Data covering the period before the Revised Rule 21 was available on relative cost overruns—amounts, that is, that customers considered to be in excess of what they expected to pay.

Measurement Approach

Measuring cost effectiveness, that is, progress toward these four objectives, requires construction of a "Baseline" of what would have happened absent revisions to Rule 21 and comparing that to a "Trendline" of what actually happened. Measurement is a four-step process:

1. Collect data for a Baseline made up of interconnection projects or requirements under conditions of the old Rule 21 or equivalent non-Rule 21 situations;
2. Collect data for a Trendline made up of interconnection projects or requirements under conditions of the Revised Rule 21;
3. Compare the Trendline to the Baseline;
4. Compare results of Step #3 with the objective, to yield progress toward the objective.

Each objective has one or more Baseline data source and one or more Trendline data source. Comparison may result in qualitative or quantitative value. The following sections will cover the Baseline and Trendline data sources and methodologies for comparison for each objective.

Four data sources were used to determine cost effectiveness of California interconnections under Revised Rule 21:

1. A report titled "Making Connections" on pre-2001 interconnections from DOE[12] provided the baseline data;
2. CaIS reports (as described in Section 0 above);
3. Details of the interconnection review process provided to the FOCUS team by the three major utilities: separation of interconnection applications into those approved through Initial Review, those approved through Supplemental Review and those approved following a Detailed Study;
4. The Revised Rule 21 itself.

The overall methodology for measuring cost-effectiveness is listed below for each Objective:

Process Improvement Objective

Description: The evaluation compares the Baseline interconnection process, as applied in particular Baseline projects, with the Revised Rule 21 interconnection process. An improved process is scored as a percentage of actual achievement against a standard of complete success (where success=100%, failure=0%).

Baseline data source: Making Connections

Trendline data source: Revised Rule 21

Result: Scored qualitative comparison

[12] Department of Energy

Simplified Interconnection Objective

Description: Document results of efforts to expand applications eligible for Simplified Interconnection[13]. Under Revised Rule 21, there are three tracks to interconnection: 1. Approval upon Initial Review resulting in Simplified Interconnection; 2. Approval upon Supplemental Review either through Simplified Interconnection or with additional requirements; and 3. Approval following a Detailed Study, probably resulting in additional requirements. The first is usually the fastest and least expensive track; the third (Detailed Study) is usually the longest and costliest track. The Simplified Interconnection objective aims to measure the number of projects taking the fast track. Expanded eligibility for Simplified Interconnection counts as qualitative (non-numerical) improvement in cost-effectiveness.

Baseline data source: Making Connections

Trendline data sources: 1. Revised Rule 21; 2. Special utility interconnection reports.

Result: Quantitative comparison of total projects passing on Initial Review (and Supplemental / Detailed Study) as a percentage of total interconnections;

Time Reduction Objective

Description: Compare Rule 21 time delays in approval with baseline time delays; if Revised Rule 21 reduces interconnection delay by 20% or more for units less than 1MW, the Time Reduction Objective will be met.

Baseline data source: Making Connections, CaIS Reports

Trendline data source: CaIS Reports

Result: Numerical comparison

Cost Reduction Objective

Description: Reconstruct Rule 21 Trendline cost data from MC projects, comparing them to Baseline MC cost data; if units smaller than 1MW are reduced in cost by at least 30% from the baseline, or 15% for units equal to or greater than 1MW, the Cost Reduction Objective will be met.

Baseline data source: Making Connections

Trendline data source: Engineering estimates of Revised Rule 21 costs of compliance

Result: Estimated numerical comparison

[13] According to Rule 21, Simplified Interconnection is "Interconnection conforming to the minimum requirements under this Rule, as determined by Section I." See Rule 21, Section I for details: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html

Baselines

Baseline for Process Improvement Objective

The Making Connections report offers a "Ten-Point Action Plan for Reducing Barriers to Distributed Generation".[14]

TABLE 2-5: "MAKING CONNECTIONS" TEN-POINT ACTION PLAN

Reduce Technical Barriers
1. Adopt uniform technical standards for interconnecting distributed power to the grid.
2. Adopt testing and certification procedures for interconnection equipment.
3. Accelerate development of distributed power control technology and systems.
Reduce Business Practice Barriers
4. Adopt standard commercial practices for any required utility review of interconnection.
5. Establish standard business terms for interconnection agreements.
6. Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.
Reduce Regulatory Barriers
7. Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.
8. Adopt regulatory tariffs and utility incentives to fit the new distributed power model.
9. Establish expedited dispute resolution processes for distributed generation project proposals.
10. Define the conditions necessary for a right to interconnect.

These ten points will be treated in this paper as baseline conditions that, if fulfilled by the new Rule 21, are considered evidence of qualitative fulfillment of the Process Improvement Objective. The rationale for this approach is that to the extent Rule 21 is making progress toward achieving one or more of these 10 points, it is making progress toward "[improving] the process of interconnection of DG to the electrical system", as required by the Process Improvement Objective.

Some of these points do not concern interconnection and are modified or eliminated from consideration for our comparison:

- Eliminate Point #3: Control technology is beyond the scope of this study;
- Modify Point #7: Narrow to include interconnection only;
- Modify Point #8: Narrow to include interconnection only.

[14] Making Connections, Executive Summary, p. iv.

Baseline for Simplified Interconnection Objective

The Simplified Interconnection Objective baseline is simple to construct because the old Rule 21 did not provide for Simplified Interconnection.[15] All projects had to go through what is now called Detailed Study. Any interconnection requiring less scrutiny than a Detailed Study, therefore, represents progress toward the objective. Evidence for this progress is found in the Revised Rule 21. To the extent that Revised Rule 21 provisions and Certification provide process improvement and opportunities for Simplified Interconnection or Supplemental Review (thereby avoiding a Detailed Study), they successfully fulfill the Simplified Interconnection Objective.

The 65 Baseline interconnection projects tracked in Making Connections produced the following results:

- 29 were completed and interconnected—no detail was given, but it is reasonable to assume they operate in parallel with the grid (on-site load with no export);
- 9 were interconnected and are explicitly operating in parallel with no export;
- 2 were disconnected from the grid, and it is unknown whether they are operating isolated from the grid or were shut down;
- 7 were installed (at time of writing of Making Connections) but were not then interconnected, though perhaps operating isolated from the grid (i.e. not in parallel with the EC) in the interim;
- 13 were pending (at time of writing of Making Connections);
- 5 were abandoned.

Time Reduction Objective

The Baseline for the Time Reduction Objective comes from these sources:

- The Making Connections report;
- The California DG lists (CaIS Reports), modified and prepared as shown in Table 2-4.

There are sixteen projects in the California Time Delay Baseline—four from Making Connections, twelve from the CaIS list. For this report, Time Delay is defined as the time span to interconnect beyond what the developer thought was reasonable. The project delays range from 30 days to 286 days. The following table shows the results for California, sorted in ascending order of length of delay in days.

[15] A project qualified for Simplified Interconnection is one that is approved following only the Initial Review, and in some cases following the Supplemental Review, and does not require a Detailed Study.

TABLE 2-6: CALIFORNIA INTERCONNECTION TIME DELAYS

State	*Project ID*[16]	*kW*	*Technology*[17]	*Time Delay Total days*
CA	13.32CA	132	PV	30
CA	0.52CA	2100	Wind	61
CA	0.01SCE	235	FC	92
CA	0.01SDGE	23,500	NGCT	100
CA	0.07SDGE	200	NGIC	117
CA	0.57SDGE	400	NGIC	117
CA	0.02SCE	1,275	NGIC	117
CA	0.03SCE	14	PV	144
CA	0.04SCE	14	PV	144
CA	0.10CA	7.5	PV/Propane	152
CA	0.22CA	37	NG Turbine	183
CA	0.05SCE	60	NGMT	201
CA	0.08SDGE	400	NGIC	240
CA	0.04SDGE	14,769	NGCT/Steam	255
CA	0.06SDGE	200	NGIC	265
CA	0.05SDGE	200	NGIC	286

Cost Reduction Objective

Ultimately, all impacts result in a cost impact, and it is the cost reduction that is the most significant benefit for DG interconnections. While this study will endeavor to reach meaningful conclusions, four facts restrict and inform possible ways of constructing the cost metric:

[16] The Project IDs are different for CaIS projects than for projects in Making Connections. The CaIS Project IDs are comprised of a sequential number #.## (numbered sequentially for each utility by date the application was received), followed by the three- or four-letter acronym for the California utility service territory where they are located. The Making Connections Project IDs are comprised of a sequential number ##.## followed by the state two-letter code for the state in which they are located. The two most significant digits of the sequential number denote the Making Connections Case Study number (from 1-26). If the project is not included in the Making Connections Case Studies, the corresponding number in the Project ID is 0. This ID system was invented specifically for this paper because it became necessary to link up project characteristics in Making Connections and to eliminate redundancy and avoid double counting in the CaIS lists. No ID system is implemented in either original source. The ID system facilitates quick distinction between the CaIS projects and the Making Connections projects and allows tracking of specific projects and cross-referencing by interested readers.

[17] PV= Photovoltaic; NGMT= Natural gas microturbine; NGIC = Natural gas internal combustion engine; FC = fuel cell; NGCT = Natural gas combustion turbine.

- No hard cost data were available for the NREL study relative to either the cost to the utility of an interconnection study or to the cost to the developer of installing and testing required interconnection equipment;
- No hard cost data were available for the period after 12/21/2000 when the Revised Rule 21 went into effect.
- CaIS and some Making Connections projects contain time delays but no cost information.
- Most of the Making Connections costs are estimates and were not actually incurred at the time the report was written.

Using Relative Cost Data

To overcome the first two restrictions, the baseline costs were examined to assess whether they would accrue to the project under the Revised Rule 21. If the Revised Rule 21 creates a condition or conditions that eliminate the cost, that is counted as progress toward the Cost Reduction Objective. It is not always possible to know what conditions caused the cost in the first place since the costs of detailed interconnection studies are not available. However, the requirements in the new Rule 21 were put in place to eliminate costly interconnection fees, detailed studies, and burdensome technology-specific requirements wherever functional requirements could ensure safety and reliability of the grid. Given the myriad contingencies however, no one expects the Revised Rule 21 to be able to foresee all interconnection situations at actual sites. There are many areas where the technical requirements are not spelled out in Rule 21. In these areas, the utility has discretion. Projects in the baseline that fall into one of these gray areas will not be used, since Revised Rule 21 gives no clear advantage over the old Rule 21 situation. Constructing the cost baseline, therefore, requires a project-by-project assessment of whether Revised Rule 21 would impact the Baseline project cost. Projects with insufficient information to make a determination are excluded from the results. MC estimates, where given, are used at face value.

Carrying Cost of Money

The lack of cost data in the CaIS projects cannot be overcome, except by engineering estimates, because interconnection labor and material costs aren't available. One calculable cost associated with delay is derived from the interest rate paid for capital borrowed to finance the project. The third restriction described in Section 0 can be overcome for carrying costs by attributing an assumed cost of money to each technology and time delay, thereby quantifying its cost. That way, all CaIS projects may be included in the cost overrun Baseline and Trendline and a portion of interconnection cost overrun may be accounted for. All Making Connections projects with reported time delays can be valued in the same way. Including projects without labor and material cost overruns is equivalent to setting those cost overruns to zero—in other words, the interconnection costs what the customer *expects* that it should cost, and no more. Although this is probably not a totally accurate picture, it is a conservative assumption and useful for assessing overall cost-effectiveness.

To derive the time value of money, or carrying cost, assumptions were made about how much money is spent during the process of interconnection. This varies considerably from one project to the next, so it makes sense to choose values that represent average expenditures for each technology type. The rationale behind assessing these costs is that if the technology had been installed and the project up and running at the customer's expected online date, the investment would be available to produce returns. But because of the delays, it is necessary to continue paying interest on the capital cost of the project without receiving any returns.

Many factors are involved in the overall purchase and installation cost of distributed energy resources (DERs). A recent study of the market in California for Combined Heat and Power (CHP) contains a table of approximate cost per kW for a variety of prime movers and sizes, useful for the purposes of this analysis.[18]

TABLE 2-7: CARRYING COSTS FOR VARIOUS DER TECHNOLOGIES AND SIZES

Representative On-site Generation Cost and Performance	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine	PV	Sm Wind	Lg Wind
Size kW	50	100	200	800	5,000	25,000	10	10	1000
Heat Rate (Btu/kWh HHV)	11,741	11,147	6,205	9,382	9,125	7,699	n/a	n/a	n/a
Recov. Exhaust Heat (Btu/kWh)	4600	1600		1200	3709	2800	n/a	n/a	n/a
Recov. from Coolant (Btu/kWh)		2600	1600	2500			n/a	n/a	n/a
Package Cost ($/kW)	$350	$500	$900	$300	$300	$300	$4,000	$3,000	$800
Heat Recovery	$150	$100	$75	$75	$75	$75	$0	$0	0
Emission Controls	$0	$70	$0	$29	$51	$50	$0	$0	0
Project management	$18	$25	$45	$15	$15	$15	$45	$45	45
Site & Construction Management	$25	$35	$63	$21	$21	$21	$63	$63	63
Engineeering	$14	$20	$20	$12	$12	$12	$20	$20	20
Civil	$50	$75	$100	$38	$15	$13	$100	$100	100
Labor/Installation	$70	$100	$120	$38	$45	$45	$120	$120	120
CEMS	$0	$0	$0	$0	$30	$20	$0	$0	0
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15	$0	$0	0
Interconnect/Switchgear	$50	$75	$38	$31	$10	$3	$38	$38	37.5
Contingency	$18	$25	$27	$15	$15	$15	$27	$27	27
General Contractor Markup	$78	$103	$139	$57	$61	$58	$139	$57	$61
Bonding/Performance Guarantee	$24	$31	$14	$17	$18	$18	$14	$17	$18
Carry Charges during Constr.	$15	$20	$27	$11	$24	$23	$80	$61	$45
Carry Costs per kW per day	$0.0424	$0.0555	$0.0738	$0.0310	$0.0660	$0.0633	$0.2189	$0.1672	$0.1239

The table makes the following assumptions:

- Of total construction cost, 50% has been paid during the period of interconnection delay;
- Interest rate is 7%;
- Construction (for a project without delays) takes 1 year for units 1MW+ and 6 months for units <1MW.

---

[18] http://www.energy.ca.gov/reports/2000-10-17_700-00-009.PDF, Onsite Energy, "Market Assessment of Combined Heat and Power in the State of California, July 1999. PV costs come from http://solstice.crest.org/articles/static/1/binaries/REPP_FL_100202.pdf. Wind costs come from http://www.energy.ca.gov/distgen/economics/capital.html.

The final line simply divides the "Carry Charges during Construction" by days per year to show the carrying costs per kW per day. To derive the total cost overrun due to delay, the technology and size are matched to the project, and the carrying cost per kW per day is multiplied by the number of days of delay.

Lost Opportunity Cost

Perhaps the biggest cost associated with delays in interconnection is the lost opportunity cost. Opportunity costs consist of project revenue, as from sales (or avoided cost of purchase) of electricity, of an electric generator. These revenues are "lost" when there is a delay in completion of the project. In this instance, the delay of concern is for interconnection. Data on opportunity cost is usually proprietary, so a surrogate means for estimating this cost was developed, using conservative assumptions. For example, it is assumed that an investor in DG would probably not accept less than a 6.5% return on invested capital.[19] Assume that a 100kW power plant with a 50% capacity factor costs $2000 per kW installed, or $200,000. It will run 4380 hours per year and (assuming 100% operation during these hours) generate 438,000 kWh per year. A 6.5% return on $200,000 invested would equal $13,000 per year, or about $0.03/kWh. This figure is used for all units under 1 MW.

Costs per kW for units 1 MW and above are assumed to be $1000/kW, so that $0.015/kWh would generate a 6.5% return if run half time. If the operating hours are shorter—a peak shaving application, for example—the ROI per kWh would have to be higher to support the same return; and vice versa. The table below shows four common operating modes, hours approximations, and required ROI/kWh to maintain 6.5% return.

TABLE 2-8: HOURS ASSUMED FOR OPERATING MODES

Operating Modes	*Hours/year*	*$/kWh ROI*	*Hours breakout*
Cogeneration	5,200	$0.025	16hrs M-F; 10hrs S/S
Peak Shaving	2,080	$0.063	8hrs M-F
Primary Power	6,307	$0.021	8760 x 72% available
Emergency/Backup	100	$1.300	Extended emergency

Savings in Interconnection Fees and in Interconnection Costs

The simplified processes developed under the Revised Rule 21 have a fixed fee associated with Initial Review ($800) and with Supplemental Review ($600). Before Revised Rule 21, all applications had to undergo an Interconnection Study. The requirements imposed on simple

[19] This number is arbitrary, though probably low; DG is still a somewhat risky investment and one would expect a return commensurate with the risk.

interconnections could be severe. Utility protection engineers knowledgeable with interconnecting large power plants to the transmission grid, but unfamiliar with interconnecting small plants tended to impose unnecessarily burdensome requirements. Detailed Study is estimated here to cost $7,500—a conservative figure supported by recent anecdotal evidence. The cost difference calculated for each project between old and Revised Rule 21 equals $6,100 for Supplemental Review and $6,700 for Simplified Review—average $6,400.

The Cost Comparison Baseline

The interconnection cost overrun per kW, the delay carrying cost per kW, lost opportunity cost, and the interconnection cost are included for every project in the Baseline for economic objectives (see Appendix A). Projects that do not have adequate cost or time data are marked "n/a". The Cost Objective has targets for units under 1MW (30% cost reduction) and for units 1MW and above (15% cost reduction). Progress toward these targets and an assessment of all costs included in the previous section (2.5.1) is described in Section 3.3.2.

Perhaps the greatest initial cost and reason for interconnection delay is the lack of information provided to project developers and others who are involved with interconnection under California's Rule 21. To fill this gap, the Energy Commission directed a FOCUS-II team to prepare a California Interconnection Guidebook to help engineers through the technical and regulatory processes of interconnection.

2.4 The California Interconnection Guidebook

The tariff Rule 21 defines precisely the requirements for interconnecting at the level of the distribution system. It is written in language that expresses the requirements accurately and concisely. It is not meant as a primer on interconnection; in fact, it can be quite difficult to understand even for engineers (except for protection engineers) and attorneys, and more so for regulators and electricity customers looking to interconnect electricity generators in the field. There is a need for an easy-to-use field guide for interconnection; this is the need the Guidebook fulfills. The purpose of the Guidebook is to assist customers in interconnecting their generators to the electricity distribution system according to Rule 21 of the CPUC. It applies to customer facilities in the utility territories of PG&E, SCE, and SDG&E. The Guidebook explains the interconnection process and provides information for each step. It does not assume previous interconnection experience but recommends that an electrical engineer with experience can help ensure successful interconnection.

2.4.1 Introduction

The Guidebook discusses the division of the electric grid into two systems: the transmission system that transfers power at high voltages from power plants to utility substations and a few large customers; and the distribution system that delivers power from the substations at medium and low voltages to most customers. The Federal Electricity Regulatory Commission (FERC) primarily regulates wholesale transactions and the transmission system, and the CPUC regulates retail transactions and the distribution system. Rule 21 applies to interconnecting generation that is supplementary to a customer's retail service. Usually a substation distributes power from the transmission system's high voltage, ranging from 60 kilovolts (kV) to 500 kV, by converting it to the medium range between 4 kV to 60 kV. Distribution system feeders then carry the power to the customers. Although the transmission system uses bi-directional flow of power on the same transmission line, the distribution system usually is unidirectional from the substation to the customer. The radial distribution system sends out distribution lines called "feeders" from the substation hub in a one-way flow of power. In urban high-density load areas a network secondary distribution system uses multiple sources and paths in order to reduce outages in the event of a fault in the system. Network protectors prevent power from flowing back into the radial feeders and are called grid networks. Transformers, wires, switches, and equipment for protection and control make up the complicated distribution system. Electric utilities have the responsibility of providing reliable power to customers at all times, despite the fact that distribution feeders and customer loads vary greatly in capacity. About one-third of an electric bill goes into maintaining and operating the distribution system. This system was not originally designed for receiving power from a customer's generator. Thus in the interconnection application the utility must evaluate the impact the customer's generator may have on the system.

The Guidebook primarily is for **parallel operation**, which is when the generator produces alternating-current power while it is electrically interconnected to the local utility's distribution system. The distributed generator must match the voltage magnitude and frequency of the utility's system, and it must meet standards for power quality while not interfering with the utility's protective and reliability functions. Five different methods of interconnection depend upon the mode of operation, one for isolated and four for parallel.

1. **Isolated operation** is when the customer's facility generates power consumed by loads isolated from the utility (see the "Stand Alone" facility in Figure 1-1). No interconnection agreement is needed only if it is permanently wired for only isolated operation. If a switch can transfer load from the utility to the generator and back, then utility approval is necessary.

2. **Non-exporting generation** is when all the power is consumed by the customer's load. This is the most common type of interconnection in California. Rule 21 describes the following three methods to make sure that a generating facility is non-exporting: the reverse power function decreases generation if power flows to the utility's system above a threshold for a certain period of time (Initial Review Process Screen2, Option1) the under power function makes adjustments if the power flowing from the utility's distribution system is less than a threshold for a period of time (Initial Review Process Screen 2, Option 2); and the third method is for the generator's output capacity to be a fraction of the customer's minimum load so as to assure that the customer load will always be greater than the generation (Initial Review Process Screen2, Option3).

3. **Inadvertent and incidental export** may occur when a sudden reduction of the customer's load causes an inadvertent export while the generator reduces power production (Inadvertent) or when the level of export is small relative to the capacity of the customer's service equipment (Incidental). The interconnection needs to be designed to minimize the power exported.

4. **Net energy metering** is used by generating facilities such as wind and solar that use renewable fuel and export power during peak resource conditions but use energy from the utility

at other times. The energy exported to the utility is subtracted at the regular retail tariff rate from the energy supplied by the utility; the result is shown on the customer's bill.

5. **Exporting for sale** (generating electricity in order to sell it to the utility) is not covered under Rule 21 at present; California is presently closed to selling electricity to other private customers.

Briefly, Rule 21 has sections on the following topics:

- Section A pertains to the requirements for interconnecting, operating, and metering distributed generators connected to the electric utility.
- Section B explains the general requirements, which include: a written agreement; complying with applicable laws, rules, and tariffs; and cooperating with the utility's performance design reviews and inspections with confidentiality for the customer and possibly curtailment and disconnection of the generating facility.
- Section C explains how generating facilities apply for interconnection, the review and possibly a study, installation to or modification of the distribution system, testing, authorization, and reconciliation of costs and payments.
- Section D describes the design of the interconnection system and its operating requirements, including general interconnection, preventing interference with the distribution system, and how to control the power with protective functions and safety equipment.
- Section E discusses additional requirements related to ownership and cost limits, exemptions, and extra agreements regarding improvements installed for the interconnection.
- Section F explains metering, monitoring, and telemetering at the customer's generator.
- Section G delineates the process for resolving disputes.
- Section H defines terms pertinent to interconnection.
- Section I describes how the utility reviews the application for interconnection. The screening of an Initial Review enables some customers to qualify for a Simplified Interconnection. Others that fail one or more screens must move on to a Supplemental Review, which determines if a detailed interconnection study is needed or if the application may pass subject to Supplemental requirements.
- Section J explains the certification and testing criteria. Using equipment already certified by the manufacturer may speed up this process. There are four kinds of testing. Type testing determines if equipment meets the specifications of certified equipment. Production testing includes voltage and frequency variation tests. These tests are sufficient for a single generator using a low percentage of its capacity. Commissioning testing is done at the site of the generating facility in order to verify the settings of the protection functions and may test voltage, frequency, non-islanding, non-exporting, and other functions. Periodic testing is prescribed by the manufacturer and must be performed within four years.

2.4.2 Interconnection Application and Approval

Application for approval to interconnect distributed generation is made to the local utility. The four major steps of this process are filling out the application, the electric utility's review of the generating facility, the interconnection agreements, and the installation and commissioning.

2.4.3 Technical Requirements and Certified Equipment

Rule 21 explains the technical requirements for interconnection in three parts of Section D. First, all generating facilities must meet general interconnection and protection requirements. Second, the utility must make sure to prevent any interference with the power quality of its system. Third, it discusses the protection requirements for synchronous generators, induction generators, and inverter-based generating systems.

Type tests, production tests, commissioning tests, and periodic tests are used to make sure that certified and non-certified equipment meets the requirements, though using equipment certified by a nationally recognized testing laboratory (NRTL) reduces the number of these tests.

A verification committee makes sure that Rule 21 requirements have been met.

2.4.4 How to Apply for Interconnection

The application form may be obtained from the Energy Commission and individual utility websites. The design drawings (that must be provided along with the interconnection application) need to be reviewed and approved by a California-registered professional electrical engineer. An electrical plan checker will review the drawings to make sure that the design complies with the electrical code. The utility will examine the application to see if the design meets the requirements of Rule 21. During the review the utility may contact the applicant about deficiencies and the need for corrections, which may require resubmitting drawings.

In completing the application four copies of documents must be submitted according to engineering standards. These documents include the following:

- A single-line drawing should depict the electrical relationships and components of the generating facility, and its relationship to the distribution system.
- Site plans and diagrams should show the physical relationship of the components such as generators, transformers, switchgear switchboard, control panels, connections to the customer's loads, and interconnection to the distribution system.
- If a transfer switch is used, its components, capacity ratings, and operation should be described.
- If protective relays are used, diagrams should depict the relay wiring and connections along with the settings and the protective function.

Other information in the application includes the location of the generating facility, the contact person, and the proposed date of operation.

In Part 3 of the application the generating facility and the customer's electrical facilities must be described. First, one must indicate how the generating facility will interface with the distribution system. The three options are parallel operation, momentary parallel operation, and isolated operation. In parallel operation the generating facility is synchronized with the prevailing voltage and frequency of the utility and provides some or all of the power for the local loads. Any excess energy may be exported to the distribution system. In momentary parallel operation the synchronization lasts only long enough (less than one second) to enable a smooth transition to isolated operation. The utility may require verification that this transfer will occur within one second or that the generator will shut down. In isolated operation the generation does not operate in parallel with the utility at any time. Emergency backup generators usually operate in isolation.

If the customer chooses parallel operation, the type of agreement requested must be indicated. If the customer also chooses the no- or low-export agreement, there are four options that will prevent energy from being exported to the utility's distribution system. The reverse-power protective function is designed to trip or isolate the generator if reverse power exceeds a threshold. The under-power protective function reduces the generator's output if the minimum import power falls below a threshold. The low export option makes sure that any power exported is small relative to the distribution system's capacity. The minimum load option verifies that the generating facility rating does not surpass 50% of the customer's minimum electrical load; minimum load information must be included.

How the generating facility will be operated must be explained. The utility needs to be able to estimate the customer's power requirements. Combined heat and power (CHP) or cogeneration uses heat from generators to heal or cool buildings, to heat water, and for manufacturing. A generating facility may be used to reduce electrical power during peak utility periods when the price is high by reducing energy consumption and demand. A primary source of power may only need the utility for supplemental, standby, or backup power. Conversely, a generating facility may only operate when the utility's electrical supply is not available as a backup during emergencies. Net energy metering is another alternative use of energy. The customer must indicate if one has obtained Qualifying Facility Status from the Federal Energy Regulatory Commission (FERC).

In Part 4 the customer must describe its generating units by indicating the types of generators being installed, whether its design is synchronous, induction, or inverter. The following information also needs to be included: gross nameplate rating in kVA and in kW, the net nameplate rating in kW, operating voltage in volts/kV, the power factor percentage, the minimum and maximum percentages of the power factor adjustment range, whether the wiring configuration is single-phase or three-phase, the kind of 3-phase wiring configuration, whether the neutral grounding system used is ungrounded, solidly grounded, or a ground resistor; the short circuit current produced by the generator in amps, and whether the prime mover is an internal combustion engine, a microturbine, combustion turbine, or fuel cell (and which fuel they use) or a steam turbine, photovoltaic panels, solar-thermal engine, hydroelectric turbine, or a wind turbine.

2.4.5 Electric Utility Review

The Initial Review Process (Figure 2-2) is designed to implement rapid approval for generating facilities that do not need a detailed interconnection study. This process uses a series of screens to identify site-specific issues that may need to be reviewed more fully before interconnection. If a screen is not met, then the Supplemental Review determines whether an Interconnection Study is required or if the condition may be satisfied by additional known requirements. The screens also help the customers identify problems before the review process. The Supplemental Review is more extensive and allows the applicant to re-evaluate the interconnection plan.

The first screen asks if the point of common coupling (PCC) is on a networked secondary distribution system, because the utility gives special attention to generators on such secondary systems. Radial distribution systems do not have network protectors and therefore do not have those concerns. In the United States, operating experience with generators in secondary networks is limited, and the Working Group believed it was premature to develop specific screens. Thus siting a generator in a secondary network necessitates a Supplemental Review.

The second screen asks if power will be exported across the PCC, because systems that export little or no power across the point of common coupling have much less impact on the local distribution system. However, generating facilities that export large amounts of power or those that export power inadvertently because of operational constraints need to respond to the concerns of the distribution system. Systems that export power purposely and significantly have a greater chance of contributing to unintentional islands and may impact the utility's voltage regulation. Rule 21 defines islanding as "a condition on the utility's Distribution System in which one or more Generating Facilities deliver power to Customers using a portion of the utility's Distribution System that is electrically isolated from the remainder of the utility's Distribution System." Though this theoretically may be done with utility approval, there is concern that such a condition may occur "unintentionally"—without utility control or approval—as a consequence of specific load and generation conditions.

Four options are available for complying with the second screen. First, to make sure that power is not exported, a reverse power protective function may be implemented at the point of common coupling. The default setting for export should be 0.1% of transformer rating with a maximum two-second time delay. This reverse-power relay device opens whenever the on-site generator exports power beyond a designated threshold. The second option insures a minimum import of power by implementing an under-power protective function at the point of common coupling. The import default setting should be 5% of the generating facility gross nameplate rating with a maximum two-second delay. The under-power relay works similarly to the reverse-power relay. The third option is to limit the export of power by meeting three conditions. 1) The aggregate capacity of the generator should not exceed 25% of the nominal ampere rating of the customer's service equipment. 2) The total aggregate generating capacity should not exceed 50% of the service transformer rating. 3) The generator must be certified to be non-islanding. The fourth option insures that the relative capacity of the generator compared to facility load produces no export of power without using additional devices by making sure that the generator's capacity is not greater than 50% of the customer's verifiable minimum load over the past year.

The third screen asks if the interconnection equipment is certified under Rule 21 for this application, or if it has the utility's approval. The protective functions need to be rigorously tested, whether they are implemented through discrete relays, multi-function relays, or as part of an integrated control system. Once a NRTL has tested and verified a piece of equipment, it is not necessary for a utility to test it again. Interim approval by the utility allows non-certified equipment to be accepted without more testing, because the utility is already familiar with its use in interconnection.

The fourth screen asks if the aggregate generating capacity on the line section is less than 15% of line section peak load. This requirement ensures that the aggregate generating capacity on a line section is well below the maximum peak load.

The fifth screen asks if the starting voltage drop is within acceptable limits. This only applies to generators that start by motoring to operating speed, as induction generators do. Two options are available for complying with this screen. 1) The utility may determine that the generator's starting inrush current is less than the continuous ampere rating of the customer's service equipment. 2) The utility may ascertain the impedances of the service distribution transformer and secondary conductors to the customer's service equipment and make a voltage-drop calculation. Or it may use tables to figure out the voltage drop. The voltage drops caused by starting the generator must be less than 2.5% for primary interconnection and 5% for secondary interconnection.

The sixth screen asks if the gross nameplate rating of the generator is 11 kVA or less in order to put a lower limit on the necessity of reviewing the short circuit current contribution and the line-configuration screens. This screen enables very small generators to bypass the last two screens.

The seventh screen asks if the short circuit current contribution is within acceptable limits. At the primary side of the dedicated distribution transformer, the total of the short circuit contribution ratios (SCCR) must not exceed 0.1. At the secondary side of a shared distribution transformer, the short circuit contribution of the generator must be less than 2.5% of the interrupting rate of the producer's service equipment.

The eighth screen asks if the line configuration is acceptable for simplified interconnection. If the generating facility is served by four-wire systems, then its aggregate capacity beyond 10% of the line section peak needs to be reviewed.

Project personnel need to be accessible to requests for further information in order to keep the review process on track. The review process has three possible outcomes: the generating facility may qualify for Simplified Interconnection; a Supplemental Review may be needed to determine additional requirements; or a Detailed Study may be required. The Supplemental Review also has three possible results: no additional requirements may be necessary for interconnection; some additional requirements or corrections may be needed to allow interconnection; or a Detailed Study—an engineering review of specific aspects of the proposed generating facility's interconnection to the distribution system—may be necessary. The Detailed Study can be expensive and time-consuming.

2.4.6 Interconnection Agreements

The interconnection agreements of SCE, SDG&E, and PG&E are similar with a few minor differences, which are explained in the *Guidebook*. SDG&E has a Generation Facility Interconnection Agreement (GFIA), a GFIA for Inadvertent Export, a Customer Generation Agreement, a GFIA for Third Party Inadvertent Export, and a GFIA for Third Party Non-Exporting. Southern California Edison also has five agreements with the same names having minor differences from SDG&E. PG&E has only three agreements, and it makes no accommodation for inadvertent export. The utility determines which agreement is right for the customer.

2.4.7 Installation and Commissioning

Installing the generating facility should proceed according to the interconnection agreement, following the designs and using the equipment approved in the application review. Any changes should be approved by the utility. Operating the generator before gaining the approval of the utility risks liability for injury and damage. In the commissioning a competent installer performs tests during the installation to make sure that the generator is installed and functioning properly so that any mistakes can be corrected at the start. Rule 21-certified generating facilities require less commission testing and may be a factory-assembled system that has been tested as a package. Commission testing of non-certified equipment is specified in the interconnection agreement.

2.4.8 Problem and Dispute Resolution

If a problem or dispute arises over the interconnection, there are three possible steps for resolving it. First, one should seek resolution through project meetings. Second, one may seek resolution under Rule 21. Third one may appeal to the California Public Utilities Commission (CPUC).

Rule 21 Section G describes four steps for dispute resolution: 1) write a letter to the other party with the facts of the dispute and the relief you want; 2) plan a meeting with the other party within 45 days of the dispute letter; 3) attempt to reach consensus; 4) if consensus is not reached, the issue may be submitted for resolution by the Commission’s procedure. The CPUC will then decide. One may file a formal dispute with CPUC, but it also has an informal resolution process in its Consumer Services Division. Many small disputes are resolved this way in a few days. One begins by filing a complaint. The three steps in the informal process are phone resolution, supervisory review, and a conference.

2.5 FOCUS Support for IEEE Activities

A key function of the FOCUS team is to maintain active participation in relevant outside standards development activities. Such participation serves the dual purpose of ensuring both that the Rule 21 workgroup is kept abreast of the latest activities and information as it’s being developed, and that those broader standards groups receive the benefit of the Rule 21 workgroup process. Both of these purposes serve the overall goal of standardizing interconnection requirements. FOCUS team members participated in a number of relevant national standards activities including:

- AN SI/IEEE Std 1547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems
- UL 1741 Inverters, Converters, and Controllers for Independent Power Systems
- IEEE P1547.1 Draft Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- FERC Small Gen Advanced Notice of Proposed Rule Making

2.5.1 IEEE 1547 and its Impacts on Rule 21

Even before the Rule 21 workgroup process began, IEEE began development of a national interconnection standard for distributed generation. IEEE P1547 *Standard for Interconnecting Distributed Resources with Electric Power Systems*[20] (the "P" in the standard number means "project" and is removed once the standard is published) was initiated in December 1998. The impetus for IEEE P1547 was similar to that of the Rule 21 workgroup process: standardize interconnection requirements to reduce and remove perceived barriers to the implementation of DER. While Rule 21 was written specifically for California's IOUs,[21] the new IEEE standard was intended to become a national standard and have application internationally. The standard became popular, a stake in the ground that DG suppliers, utilities, and regulators all felt compelled to support. While Standards Coordinating Committee 21 meetings had typically attracted 20-30 participants per project prior to P1547, meetings for this new standard were two to 10 times larger than that. The working group included nearly 400 members and 230 people were on the balloting committee.

Over a period of nearly 4.5 years:

- Almost 20 working group meetings were convened;
- About twice that many writing committee meetings were held;
- Eleven drafts were developed, including hundreds of pages of support and reference materials;
- Four ballot actions were taken.

While the working group brought all interested parties together to discuss the latest drafts, a writing committee was charged with the lion's share of writing, and of trying to reconcile the disparate opinions of the working group. Initially, the writing committee consisted of 10 individuals selected by Chairman Richard DeBlasio. Following ballot actions on Drafts 7 and 8 that failed to garner the 75% minimum approval requirement, Chairman DeBlasio changed the makeup of the writing committee, adding 15 new "writers" (including PG&E's Chase Sun and FOCUS team member, Chuck Whitaker; Doug Dawson, a key contributor to the Rule 21 proceedings had been a member of the original writing committee). In January 2002, the new writing committee was charged with reducing the text of the standard to the bare technical requirements with a goal of condensing the document to less than half of Draft 8's 41 pages.

The Federal Energy Regulatory Commission (FERC) had initiated its own process to define standardized interconnection requirements for distributed generation installed under its jurisdiction (transmission-connected DG and DG intending to export energy for sale on the wholesale market). Two Advanced Notices of Proposed Rule Making (ANOPR) were published to develop those requirements:

---

[20] Visit http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

[21] With the participation of numerous public utilities, many adopting or planning to adopt interconnection requirements based on Rule 21.

- For large generation 20MW+ : ANOPR Docket No. RM02-1-000 Standardizing Generator Interconnection Agreements and Procedures, October 25, 2001;[22]
- For small generation < 20MW: Docket No. RM02-12-000, Standardization of Small Generator Interconnection Agreements and Procedures, July 24, 2003.[23]

While the FERC process clearly favored adopting an approved IEEE 1547, the contentious nature of the IEEE process (which, by most opinions was far less contentious than that in the FERC proceedings) and the two failed ballot actions did not install confidence that an IEEE standard was forthcoming. FERC would develop its own technical requirements, if necessary.

The fear of having technical requirements developed under the more politically charged environment of the FERC proceedings helped inspire the working group to come to compromise and achieve consensus. The ballot action on Draft 10 in September 2002 resulted in over 90% approval. A recirculation ballot on Draft 11, which included minor changes in response to negative ballots, and which was accompanied by writing committee responses to each of the issues raised by each of the Draft 10 negative balloters, achieved a slightly better 91% approval. The IEEE standards board approved the document in June 2003 and IEEE 1547-2003 was published in July.

Because of its voluntary nature (like most standards, IEEE standards are implemented through adoption by a jurisdictional body), because of the popularity of the topic and the diversity of interests that made up the working group, and because of the internal and external pressures to complete the document quickly, the scope of the document had to be limited. For example, it is inappropriate for an IEEE standard to assign authority for decision-making. While it is readily agreed that the utility protection engineer would ultimately define and approve specific trip settings, the authority to do so is granted to the engineer by a jurisdictional body such as a public utility commission or a board of directors. Thus, IEEE 1547 could not presume to define who would approve such settings, a reality that led to many lengthy debates and some awkward language. Another limitation, and a key reason for all three of PG&E's balloters voting negative on the document, was that 1547 does not attempt to address system impacts. This fact is addressed in the several ways. The Introduction, states

> It is beyond the scope of this standard to address the methods used for performing EPS[24] impact studies, mitigating limitations of the Area EPS, or for addressing the business or tariff issues associated with interconnection.

In addition, the Section 1.1 Limitations further explains

> — This standard does not define the maximum DR[25] capacity for a particular installation that may be interconnected to a single PCC or connected to a given feeder.
>
> — This standard does not address planning, designing, operating, or maintaining the Area EPS.

[22] http://www.ferc.gov/industries/electric/indus-act/gi/anopr-gen.asp

[23] http://www.ferc.gov/whats-new/comm-meet/072303/E-2.pdf

[24] Electric Power System.

[25] Distributed Resources

Thus, to be properly implemented, the standard must be part of a large package that incorporates:

- A process for evaluating potential system impacts and defining mitigation steps;
- Integration and coordination with utility planning, design, operation, and maintenance of the distribution system;
- A jurisdictional process to define responsibilities.

Rule 21 provides a clear framework into which the requirements of IEEE 1547 can be incorporated. In August 2003, the technical breakout of the Rule 21 workgroup began evaluating the requirements in IEEE 1547-2003 with the goal of revising the rule to be consistent with the national standard. Over the next 8 months and 7 workgroup meetings, including a special 2-day meeting in November, the technical breakout worked through each of the standards 22 technical requirement sections and 20 sections addressing testing requirements. In the end, IEEE 1547 language was adopted in a dozen sections of Rule 21, standard trip settings test requirements were revised, and other changes were made to make the two documents consistent. There were 14 instances where it was felt that Rule 21 was consistent with IEEE 1547, though in some cases IEEE 1547 language was inserted for clarity. Only three exceptions were taken:

- Rule 21 has no limitation on maximum DG size and did not adopt IEEE 1547's 10 MW limit;
- Rule 21 did not adopt the EMI technical requirements in Section 4.1.8.1 or the EMI testing requirements in section 5.1.3.1;
- Rule 21 did not adopt the requirements for Distribution secondary spot networks.

The last two exceptions were as much an issue of needing more time to evaluate and understand the requirements as it was any specific disagreement with the specifics of those sections. It is likely that these issues will be addressed in the near future.

2.5.2 UL 1741/IEEE P1547.1 and their Impact on Rule 21

Section J of Rule 21, Certification and Testing Criteria, defines the Type, Production, Commissioning, and Periodic testing that is to be applied to the interconnection equipment. Rule 21 requirements borrowed heavily from UL 1741. While UL 1741 was initially developed as a safety standard for PV inverters, its ongoing relationship with IEEE interconnection standards—beginning with IEEE 929-2000 and continuing through IEEE 1547-2003, and the new IEEE P1547.1—is intended to ensure that 1741 becomes relevant to all interconnection technologies. Difficulties with interpreting results to determine if Rule 21 requirements had been meet had as much to do with the lack of detailed test procedures and reporting requirements within 1741. Involvement of FOCUS team members on the UL 1741 Standards Technical Panel will ensure that not only are the technical needs identified by the Rule 21 work group met, but that informational needs are met as well (to simplify the certification verification process) and that those needs are consistently addressed independent of which laboratory performs the test. A revised version of 1741, is expected by mid 2004 and another revision to harmonize with the final version of 1547.1 will follow in mid 2005.

Early in the development of IEEE 1547, it became clear that it would be necessary to develop companion documents that either provide the details behind some of 1547's requirements, to help explain and provide examples of how the standard could be met, or to address issues beyond the scope of IEEE 1547. IEEE P1547.1 *Draft Standard Conformance Test Procedures for*

Equipment Interconnecting Distributed Resources with Electric Power Systems is one of the detail documents, providing the details of the test outlined in IEEE 1547. With a FOCUS-II team member acting as Vice Chair of the IEEE 1547.1 committee, it is no coincidence that like Section J, IEEE P1547.1 addresses type, production, commissioning, and periodic testing. Currently, the document is in its 4th draft and it is anticipated that a ballot action will occur near the end of 2004 with publication in the summer of 2005.

Publication of these two documents will signal another round of changes in Rule 21 requirements, but will likely result in a major simplification of Rule 21—most if not all of the test requirements and specifications will be referenced in those two documents rather than spelled out in Rule 21.

2.5.3 FERC Small Gen ANOPR and its potential Impact on Rule 21

As noted in Section 2.5.1, the FERC Small Gen ANOPR helped spur the completion and approval of IEEE 1547-2003. The ANOPR/NOPR process and federal court rulings have put the jurisdictional struggle surrounding distributed generation in the spotlight. While it is as yet unclear where borderline between FERC and Rule 21 will ultimately be drawn, it is somewhat reassuring to note that the technical requirements and the processes for evaluating system impacts are similar between the two. FERC is developing a screening process with clear Rule 21 roots ("not invented here" attitude, notwithstanding), and is (or will be) adopting IEEE 1547 requirements and testing.

3 Project Outcome

3.1 Develop Certification Database Specifications

Specifications are complete for the Certification Database, the DG Database, and for the Electronic application, Contract form and help system. These specifications were completed (as described below) and submitted to the Energy Commission.

3.1.1 Specifications for a Certification Database

As mentioned in Section 2.1, the Certification Database Specification consists of an Equipment database and a Testing Laboratory database. The two are linked through the Testing Laboratory element, which is a uniform resource locator (URL) hyperlink. Explanations of all elements are contained in the comment column of the schema table.

TABLE 3-1: SPECIFICATION FOR CERTIFICATION DATABASE

Distributed Resource Certification Database

Field	Units	Data Type	Rule 21 Reference	Comments
Manufacturer		string		
Model		string		
Description		string		
Ratings				
Real Power	kW	float		Nominal rated output power, real
Reactive Power	kVA	float		Nominal rated output power, reactive
Voltage	V	float		Nominal interconnection voltage (note if transformer required)
Current	A	float		Nominal rated output current
Short Circuit Current	A	float		Maximum available fault current
In-rush Current	A	float	J.3.d	For devices that use EC power to motor to speed.
PF	--	float		Nominal or Range if adjustable
Trip Points				
Factory Set		boolean		Units are production tested at the settings listed below
Fast Under Voltage	V	float		Voltage setting or range
Fast Under VoltageTiming	sec	float		Trip time pass/fail criterion
Under Voltage	V	float		Voltage setting or range
Under VoltageTiming	sec	float		Trip time pass/fail criterion
Over Voltage	V	float		Voltage setting or range
Over Voltage Timing	sec	float		Trip time pass/fail criterion
Fast Over Voltage	V	float		Voltage setting or range
Fast Over Voltage Timing	sec	float		Trip time pass/fail criterion
Under Frequency	Hz	float		Frequency setting or range
Under Frequency Timing	sec	float		Trip time pass/fail criterion
Over Frequency	Hz	float		Voltage setting or range
Over Frequency Timing	sec	float		Trip time pass/fail criterion
Additional Certifications				
Non-Islanding		boolean	J.3.b	
Non-Export		string	J.3.c	U = Under Power function, R = Reverse Power function
Certification Admin Info				
Effective Date		date		Date on which certification is effective
Effective Serial No.		string		Initial serial number for which certification is effective
Software Version		string		Version of device control software that has been certified
Test Standards				Description of test standard(s) used to test the device (i.e. UL 1741, IEEE C62.41, etc.)
Test Standards Number		string		
Test Standards Title		string		
Test Standards Revision		string		
Test Standards Date		date		
Test Laboratory		string		Laboratory name will link to separate database of Accreditation and other info

3.1.2 Specifications for a DG Database

The tabular schema for a DG Database is shown in Table 3-2. Example output of the actual spreadsheet implementation is shown in Table 2-4: Sample from a "CaIS" Interconnection Status Report.

TABLE 3-2: SPECIFICATION FOR DISTRIBUTED GENERATION DATABASE

Field	Data Type	Width	Acceptable value(s)	Comments
Interconnection	Integer	4	Positive integer > 0	
Customer type	String	25	Any	
Location	String	20	Any	
kW	Float	10	0 to 999999.999	
Technology	String	6	DIC	Diesel Internal Combustion
			NGIC	Natural Gas Internal Combustion
			MIC	Methane Internal Combustion
			NGMT	Natural Gas Microturbine (< 250 kW)
			MMT	Methane Microturbine
			NGCT	Natural Gas Combustion Turbine
			MCT	Methane Combustion Turbine
			PV	Photovoltaic
			NGFC	Natural Gas Fuel Cell
Interconnect type	String	2	P	Parallel (longer than one second)
			MP	Momentary Parallel (less than one second)
			I	Isolated (disconnected from the grid)
Operating mode	String	5	Cogen	Cogeneration
			DM	Demand Management
			PP	Primary Power Source
			E/B/I	Emergency/Backup/Interruptible
			PS	Peak Shaving
Application received	Date	8	Valid date	
Requested online	Date	8	Valid date	
Contract executed	Date	8	Valid date	
Online	Date	8	Valid date	
Status	String	1	1	Application received, engineering review in progress.
			2	Review complete.
			3	Contract to customer. Awaiting response
			4	Contract signed. Awaiting field inspection
			5	Interconnection approved. Released for operation
			S	Application suspended – awaiting further direction
			W	Application withdrawn

3.1.3 Specification for an Electronic Application

The specification for the electronic application is the complete paper-based system. No additional functionality was added to the electronic version. The purpose of the electronic version is to give the Applicant a way to fill out the application electronically (to reduce mistakes and the likelihood of incompletion), and to increase the readability of the final printed paper version. These improvements may increase utility application processing efficiency, due to reduced quality control needed and less time spent returning incomplete applications. No survey has been performed, however, that would indicate the percentage of applications that are filled out using the online form.

The help system is limited to the instructions given the Applicant in the existing paper-based application, with some instructions on help formatting and placement for an electronic help system. The Rule 21 Working group assessed the need for more detailed help based on actual user experience with the application. The help system implementation is part of the electronic application form, built in html.

The electronic application and help system[26] were built and are available today on the Energy Commission web site at http://www.energy.ca.gov/distgen/interconnection/interconnection.html (click "Online Application Form").

The electronic contract form specification consisted of the data members of the document highlighted in preparation for the production of a contract document schema. No schema was prepared because there was no means for the information from the electronic application form to propagate to the utility contract form. Therefore, schema names and data types were not assigned. Instead, all variable information was identified to make creation of a schema easier in the future, should the utilities decide to use it. A portion of the electronic contract specification is reproduced in Figure 3-1.

FIGURE 3-1: SPECIFICATION FOR ELECTRONIC CONTRACT

EC Logo

DRAFT
CUSTOMER GENERATION
AGREEMENT
GFID XXXX

This Customer Generation Agreement ("Agreement") is entered into by and between (Customer Name), a (form of entity & state of registration) ("Customer"), and the Electrical Corporation (EC). Customer and EC are sometimes also referred to in this Agreement jointly as "Parties" or individually as "Party." In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

1. SCOPE AND PURPOSE

   This Agreement facilitates the interconnection and operation of a Generating Facility owned or operated by an entity that utilizes Customer's electrical facilities to operate in parallel with EC's Distribution System.

2. SUMMARY AND DESCRIPTION OF THE PARTIES AND LOCATION OF GENERATING FACILITY

   2.1 The name and address used by EC to locate the Customer Account and electric Service Account where the Generating Facility interconnects with EC's Distribution System is:

   ____
   ____
   ____

   2.2 Customer's electric Service Account number: __________ (Assigned by EC)

   2.3 Customer's Account number: __________ (Assigned by EC)

3.2 Monitoring Grid and Power Quality Outcome

For the systems monitored, the impact of the DG upon the grid power quality was found to be very low. The impact of the grid upon DG was also very low. This was determined by comparing the impact with previous studies. While the sample was too small and the duration too short for a general conclusion, it provides some assurance that the current requirements and approval process for DG is conservative, and is adequately protecting the grid. Some of the bullets below elaborate on this finding.

The project approach of placing a minimum of two monitors at each site—one at the DG, and one on the utility side of the PCC—has yielded a significant advantage: it has made it possible to measure how many events originate on the distribution system and are propagated to the DG on the customer site and how many events originate at the customer site with DG and are

[26] No help system was built for Sections 1 and 2 of the Application because the questions there are straightforward and (mostly) self-explanatory. The help system was written for Section 3—the most technically complex part of the application form.

propagated to the distribution system. It is therefore possible, based on this sample, to estimate the relative effects the parallel systems (DG and the distribution system) are having on each other.

The details of the events are shown below.

3.2.1 SARFI: Sag and Interruption Rates

To plot a range of sag and swell values, we need to identify just one value of interest. If we consider just the incidents in which the minimum voltage fell below 0.90 per unit and temporally aggregate them with a 60-second period, then we can compute an index known as $SARFI_{90}$, which is a special case of $SARFI_{x.}$

3.2.2 Monitoring SARFI Rates

In Table 3-3, we present a summary of the indices for $SARFI_{90}$, $SARFI_{70}$, $SARFI_{50}$, $SARFI_{10,}$ and $SARFI_{100}$ for each of the FOCUS-II Monitors. The results are sorted in descending order based on the $SARFI_{90}$ value. Two PCC monitors—at Redlands and Sunnyvale—exhibit the highest rate of $SARFI_{90}$ rms voltage variations, recording 27.36 and 22.95 short-duration rms voltage variations respectively with a voltage drop below 0.90 per unit per 365 days. The average value for the $SARFI_{90}$, $SARFI_{80}$, $SARFI_{70}$, $SARFI_{50}$, $SARFI_{10}$ (sag) and $SARFI_{100}$ (swell) rates is given at the bottom of Table 3-3 and is compared to the Edison DPQ Project Service Entrance averages for the same indices.

TABLE 3-3: AVERAGE EVENTS PER YEAR BY SARFI TYPE – ALL MONITORS

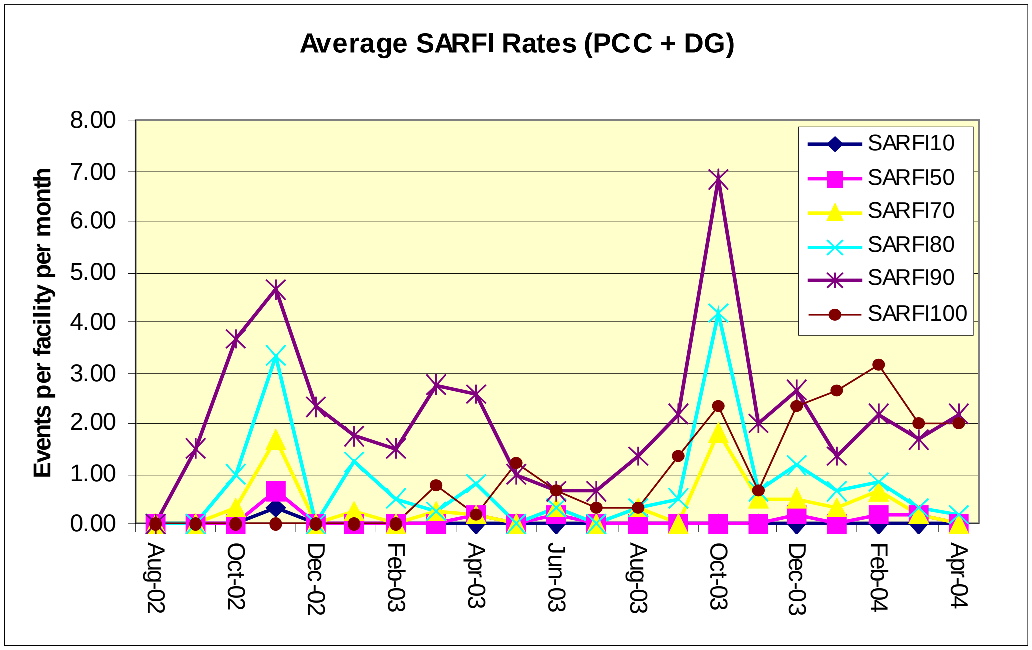
Monitor Location	$SARFI_{10}$	$SARFI_{50}$	$SARFI_{70}$	$SARFI_{80}$	$SARFI_{90}$	$SARFI_{100}$
Redlands PCC	0.59	2.38	7.73	17.25	27.36	0.00
Sunnyvale PCC	0.00	0.00	1.91	3.82	22.95	0.00
Redlands MT	0.00	0.00	1.78	7.14	16.65	0.00
South Gate PV	0.00	0.65	1.95	3.91	16.27	0.65
San Diego PCC	0.00	0.00	3.13	7.05	15.67	49.36
South Gate PCC	0.00	0.00	1.30	2.60	13.67	0.00
Sunnyvale IC	0.00	0.00	0.00	2.87	10.52	0.00
Irvine PCC	0.00	0.00	1.82	2.43	9.72	0.00
Irvine FC	0.00	0.61	1.82	1.82	6.08	0.00
Los Angeles MT3	0.00	0.00	0.00	1.15	4.58	5.73
Los Angeles FC	0.00	0.00	0.00	0.00	3.44	2.29
Los Angeles MT2	0.00	0.00	1.15	2.29	3.44	1.15
Los Angeles PCC	0.00	1.15	2.29	2.29	3.44	0.00
San Diego IC	0.00	0.00	0.78	0.78	3.13	34.47
Los Angeles MT1	0.00	0.00	0.00	0.00	1.15	1.15
All Locations Average	**0.04**	**0.32**	**1.71**	**3.69**	**10.54**	**6.32**
SCE Study Average[27]	**1.48**	**4.93**	**12.01**	**21.75**	**47.42**	**n/a**

3.2.3 SARFI Rates by Month

In Figure 3-2, we present a trend of monitors $SARFI_{90}$, $SARFI_{70}$, $SARFI_{50}$, $SARFI_{10}$, and $SARFI_{100}$ values for each month.

[27] Electrotek Concepts & Southern California Edison, “Power Quality Monitoring System: Final Report for Power Quality Data Collected at Southern California Edison from 7/1/97 to 7/1/99”, EPRI Contract Number WO7114-02, Electrotek Project Number 1054-0001, December 20, 1999.

FIGURE 3-2: SARFI RATES BY MONTH



- November 2002 shows a large jump in the rate of voltage sags (14 $SARFI_{90}$). Twelve of these events (5 on 11/8/02, 1 on 11/15/02, 3 on 11/25/02, 2 on 11/26/02 & 1 on 11/29) occurred at the Redlands site. They are unexplained but might be related to a Santa Ana condition, which occurred during this month. Santa Ana conditions have tendency to result in high winds that are hot and dry, blowing offshore from the east or northeast. These winds occur below the passes and canyons of the coastal ranges of Southern California and in the Los Angeles basin. Santa Ana winds often blow with exceptional speed in the Santa Ana Canyon. As a result, it is not uncommon for power poles to break or conductors to sway in the wind resulting in phase-to-phase shorting conditions.
- The rise in $SARFI_{90}$ events in March 2003 is due to the Irvine site where 3 events occurred. When these events are disaggregated from the 60-second event windows, it is interesting to note that 9 of the 14 sub-events occurred at shutdown of the Fuel Cell and the events were recorded first on the PCC monitor and then the FC monitor; however, each of the 3 primary events came from the FC. This more complex interaction may be attributable to the fact that just prior to shutdown, the Fuel Cell was exporting about 14 kW.
- In late October 2003 southern California was hit with one of the largest firestorms in recorded history and was the likely reason for the large number of events (19 $SARFI_{90}$) seen at Redlands from 10/24/03 through 10/29/03. In San Diego County several large fires burned, and the San Diego facility also experienced an increase in $SARFI_{70}$, $SARFI_{80}$, and $SARFI_{90}$ events, with 3, 5, and 10 events respectively.
- In October and November, the San Diego facility also experienced an increase in $SARFI_{100}$ swell events, with the monitors registering 11 events at the PCC and 3 events at the DG. The increased incidence of swells on the distribution system may also be

related to the effects of the San Diego fires. With the exception of October and November 2003, increases in $SARFI_{100}$ events appear to be unrelated to increases in the number of sags.

- The cause of the spike in February-2003 and March 2004 is unknown but is mainly recorded at Redlands site. Since the Capstone Microturbines at Redlands were not installed at the time of these events, we do know that these events originated on the distribution system.

3.2.4 Event Aggregation

A power system event occurrence is the real-world incident that triggers any number of measurements to be recorded by the ION 7600 or ION 8500. Examples include two conductors being blown together, a tree branch being brushed against one or more lines, lightning strikes, or the unfortunate act of an animal that creates an arc between part of the system and a grounded object. Other power system occurrences are planned, such as capacitor switching, and voltage reductions. We attempt to create a one-to-one relationship between temporally aggregated data and power system occurrences when computing system performance indices. Measurements were aggregated over one-minute intervals. The objective of temporal aggregation is to collect all measurements taken by the PCC monitor or the DG monitor that were due to the same power system occurrence occurring in a 60-second event window and identify them as one event. So we look at the PCC Monitor and the DG Monitor and see if an individual incident is the same. Then we compare the time stamp to find the source of the event on the DG side or the grid side of the PCC. Table 3-3 includes the unaggregated SARFI analysis for comparison with the event-aggregated totals. Table 3-4 compares SARFI results before and after aggregation.

TABLE 3-4: TEMPORAL AGGREGATION (TA) OF ANNUAL SARFI INDICES

	Monitor Location	$SARFI_{10}$	$SARFI_{50}$	$SARFI_{70}$	$SARFI_{80}$	$SARFI_{90}$
Initial SARFI Analysis	**Project Average**	0.08	0.91	4.05	9.19	29.80
	PCC Average	0.10	0.80	4.28	10.02	34.17
	DG Average	0.07	0.98	3.89	8.64	26.87
	Fuel Cell Average	0.00	0.88	3.54	4.99	21.66
	NGMT Average	0.15	1.60	4.96	11.73	28.96
	NGIC Average	0.00	0.00	2.44	7.18	20.53
	PV Average	0.00	0.65	3.25	6.51	41.66
Tempora l	**Project Average**	0.04	0.32	1.71	3.69	10.54
	PCC Average	0.10	0.59	3.03	5.91	15.47

	DG Average	0.00	0.14	0.83	2.22	7.25
	Fuel Cell Average	0.00	0.30	0.91	0.91	4.76
	NGMT Average	0.00	0.00	0.73	2.64	6.46
	NGIC Average	0.00	0.00	0.39	1.83	6.83
	PV Average	0.00	0.65	1.95	3.91	16.27

3.2.5 Statistics of Voltage Total Harmonic Distortion

Both the ION 7600 & ION 8500 have the capability to record individual and total harmonic distortion up to the 63rd harmonic (127th using ION Enterprise software).

TABLE 3-5: TOTAL HARMONIC DISTORTION SUMMARY

Monitor Location	SATHD	$STHD_{95}$	$STHD_{99}$
Irvine PCC (Commercial Building)	3.61	4.16	4.32
Irvine FC (UTC PC25)	3.61	4.16	4.32
Los Angeles PCC (Commercial Building)	1.06	1.68	1.99
Los Angeles FC (Fuel Cell Energy DFC 300)	1.06	1.68	1.99
Los Angeles NGMT1 (Capstone C30)	1.06	1.68	1.99
Los Angeles NGMT2 (Capstone C30)	1.06	1.68	1.99
Los Angeles NGMT3 (Capstone C60)	1.06	1.68	1.99
Redlands PCC (Medical Facility)	0.42	0.73	0.84
Redlands NGMT (60 kW Capstones Not Installed)	0.42	0.73	0.84
San Diego PCC (Commercial Building)	1.11	1.66	1.95
San Diego NGIC (Hess 200 Microgen)	1.11	1.66	1.95
South Gate PCC (Convenience Store)	1.22	1.73	1.96
South Gate PV (BP 14 kW PV)	1.22	1.73	1.97
Sunnyvale PCC (Manufacturing Facility)	0.12	0.42	0.55
Sunnyvale NGIC (Waukesha 3000 kW)	1.39	1.53	1.60
FOCUS-II Average	**1.30**	**1.79**	**2.01**
Edison Service Entrance Average [28]	**1.45**	**4.93**	**12.01**

[28] Electrotek Concepts & Southern California Edison, "Power Quality Monitoring System: Final Report for Power Quality Data Collected at Southern California Edison from 7/1/97 to 7/1/99", EPRI Contract Number WO7114-02, Electrotek Project Number 1054-0001, December 20, 1999.

Table 3-5 demonstrates that all of the FOCUS-II monitors are well within the 5% value specified by IEEE Std. 519-1992 for harmonic distortion. It also compares favorably with the SCE DPQ Service Entrance Averages. No unwanted harmonics have been generated by the DG in this monitoring sample. The distribution system for all sites was well within the requirements of the Standard.

3.3 Rule 21 Working Group Support

3.3.1 Rule 21 Working Group Administrative Support

From August 2, 2001 to May 3, 2004, the FOCUS-II team provided administrative support for 36 Interconnection Working Group meetings, including two technical group off-site meetings. The FOCUS-II scope of work required meeting support for up to 36 meetings—so this objective was met. The administrative support consisted of gathering all documents necessary for distribution at the workshop, preparing an agenda (as needed), preparing any analysis, commentary, or compilation of comments necessary as input to Working Group discussions, preparing and distributing meeting minutes from the previous meeting, maintaining current contact information for all Working Group participants, preparing and maintaining an Action Items list, distributing all documents and meeting announcements (as necessary), providing for logistical support (such as maps, directions to the meeting, and printouts of necessary documents) in coordination with the utility (or other) meeting hosts. FOCUS-II team member Endecon managed and coordinated all discussions for the Technical Working Group; Energy Commission staff and Rule 21 Working Group leader Scott Tomashefsky managed and coordinated discussions for the Policy Working Group.

In addition to its activities in support of the monthly Working Group meetings, the FOCUS-II team engaged in other activities within its work scope and reported on these at the Working group meetings. Major outcomes include:

- March 2003 formation of a FOCUS P1547 (IEEE Interconnection Standard) Review group to help ensure inclusion of the new Standard;
- July 2003 report on DG Monitoring systems installed and gathering data;
- May 2003 request for comment by the Working Group on the Draft Interconnection Guidebook; and
- July 2003 report that the Draft Interconnection Guidebook was completed.

3.3.1.1 Policy Group Outcomes

The policy group, in addition to the above outcomes, also achieved the following:

Date	Action Leading to Outcome	Outcome
July-01	Develop Revised Application (paper version) form	Completed
August-01	Develop Draft Interconnection Agreements	Completed
October-01	Schema for Electronic Application, Certification db, Help Topics, DG Database	Completed
December-01	Implementation of Electronic Application	Completed
January-02	Come to consensus on comments on Rule21	Consensus reached
April-02	File Rule 21 tariff letter	Completed filing - SCE
May-02	File Rule 21 uniform utility tariff letters	Completed filing - SDG&E
June-02	Riverside municipal utility considers Rule 21	Adopted as "Rule 22"
June-02	IOUs consider Interconnection Agreement tariff letters	Completed filing SDG&E, SCE, & PG&E
July-02	Bear Valley utility considers Rule 21	Rule 21 tariff letter filed
September-02	File Rule 21 tariff letter	Completed filing - PG&E
December-02	Section F (Metering) Sunset extension needed	Tariff letters filed
March-03	Develop standard Meeting Process and Action Item list	Implemented
August-03	Make Net Energy Metering tariff more integrated with Rule 21	SCE and SDG&E filed
September-03	Solicit comments on CA Interconnection Guidebook and complete it	Comments Incorporated and Guidebook completed
January-04	Complete and Present Cost Effectiveness Study to Working Group	Completed and Presented
March-04	Revise Interconnection Application form and attain consensus on revisions	Done
May-04	Revise Rule 21 and attain consensus on revisions and incorporate all revisions into a new compilation document to be used by the utilities for filing tariff letters	Revised and Incorporated and reached consensus

3.3.1.2 Technical Group Outcomes

After successfully completing the Capstone certification, requests for certification from Plug Power and Fuel Cell energy followed, in March 2002 and October 2002, respectively. Both of these inverter-based units were certified after several months of review and discussions with the manufacturer and testing lab. In August 2002, Tecogen requested certification of their induction-generator based units, the first request for non-inverter based certification. When approved in March 2003, it was the first machine-based generator to have a certified non-islanding function, a feature Tecogen incorporated specifically to meet Rule 21 requirements.

A list of all certified equipment is available online at
http://www.energy.ca.gov/distgen/interconnection/certification.html

A full list of Technical Group achievements include:

Date	Action Leading to Outcome	Outcome
January-02	Review Capstone C30 & C60 (30 and 60 kW Microturbines) for Certification	Certification verified
May-02	Review Plug Power fuel cell SU1PCM-059622 (5 kW Fuel Cell) for Certification	Certification verified
December-02	Develop and discuss Supplemental Review Guidance document	Completed & posted to website
July-03	ANSI/IEEE 1547-2003 Published; Inquiry into its incorporation in Rule 21	Initiated Standard/ Rule comparison
January-03	Review Tecogen CM-60L, CM-60H, CM-75L, CM-75H (60 and 75 kW induction generators) (without Anti-islanding)	Certification verified
March-03	Review Tecogen Anti-islanding for Certification	Certification verified
October-03	Review Plug Power MP 5000 (5kW Fuel Cell) for Certification	Certification verified
March-04	Develop modifications of Rule 21 to make consistent with IEEE 1547-2003	Modifications completed

3.3.2 FOCUS-II Cost Effectiveness Outcome

Having stated the cost effectiveness objectives and baselines and Section 2.3.4, this Section describes the measurements taken and progress indicated to date for each objective.

3.3.3 Process Improvement Objective

While no specific process improvement Baseline was stated in the FOCUS contract, MC contains an excellent proxy for comparison: the Ten-Point Action Plan shown in Table 2-5.

These ten points are treated as baseline conditions that, if fulfilled by the Revised Rule 21, are considered evidence of qualitative fulfillment of the Process Improvement Objective. The rationale for this approach is that to the extent that Rule 21 is making progress toward achieving one or more of these 10 points, it is making progress toward "[improving] the process of interconnection of DG to the electrical system", as required by the Objective. Table 3-6 shows how each of the "Ten Points" are or are not fulfilled by the Revised Rule 21. A brief narrative description of each point follows.

Table 3-6: Fulfilling the Process Improvement Objective

Barrier Types	***Baseline conditions***	***Met in Trend line?***	***% Met***	***Rule 21 Code***
Technical	1. Adopt uniform technical standards...	Y	100%	Section D, I, J, Incorporating P1547 Provisions
Technical	2. Adopt testing and certification procedures...	Y	100%	Section J
Technical	3. N/A	N/A	N/A	N/A
Business Practice	4. Adopt standard...practices for...utility review.	Y	50-100%	Section C & I
Business Practice	5. Establish standard...interconnection agreements.	Y	100%	Standard Agreements
Business Practice	6. Develop tools for utilities to assess...[DER]...on the grid.	Y	50%	FOCUS-II DG Monitoring
Regulatory	7. Develop...regulatory principles compatible with [DER]...	Y	100%	Objectives of FOCUS-I
Regulatory	8. Adopt regulatory tariffs	Y	100%	Rule 21
Regulatory	9. Establish expedited dispute resolution processes...	Y	100%	Section G
Regulatory	10. Define the conditions necessary for a right to interconnect.	Y	50%	Section B.1
Total			83%	

Point #1: Adopt uniform technical standards

Uniform technical standards have been the cornerstone of the Revised Rule 21 effort from the start. Though the Rule 21 revision effort was contemporaneous with the IEEE national technical standards development it was never the intent of the California technical interconnection group to create a separate California "standard". In fact, it was implicit that when the national standard was released, that Rule 21 would embrace it. Meanwhile, Rule 21 worked out many of the procedural details of technical implementation of interconnection requirements. As discussed in Section 2.5.1, the IEEE Standards Board published IEEE 1547 in July 2003. In August 2003, the California interconnection Working Group began the process of reconciling the technical requirements (Section D), the Initial Review (Section I), and Certification and Testing (Section J) with IEEE 1547. That process was completed in March 2004.

Point #2: Adopt testing and certification procedures

Section J of the Revised Rule 21 provides procedures for Testing and Certification for interconnection equipment primarily taking advantage of existing standards, and has been revised to be consistent with IEEE 1547-2003.

Point #3: Accelerate development of DP[29] control technology & systems

Development of control technologies is not within the scope of the FOCUS-II subcontract, nor a part of any of the California interconnection discussion, nor of Rule 21 itself. Therefore, this point is not applicable as a measure of progress toward the objective.

Point #4: Adopt standard...practices for...utility review

Section C of Rule 21 establishes standard fees and timelines for utility administration of the interconnection process. Rule 21 Section I (described in detail in Section 2.4.5) lays out in detail how the utility is to review each interconnection. The Interconnection Working Group also established a less formal guideline for Supplemental Review that describes some of the steps and processes that should go on during that process.[30] Because the IOUs are under CPUC jurisdiction to carry out the Rule 21 tariff, Section C and Section I function in California as a standard set of requirements for utility review. While the Supplemental Review guideline does not have the authority of regulatory jurisdiction, it does serve as a template for how a utility could carry out the Supplemental Review process.

Because it is impractical to consider every possible situation that might arise and to describe solutions for each, Rule 21 allows the utility some discretion in making decisions about technical requirements, for example, applications that fail one or more of the Initial Review Process screens. Although the Revised Rule 21 is nearly identical for the three IOUs, implementation of details not specified in the Rule varies among utilities. For this reason, this point varies from 50% to 100% fulfillment.

Point #5: Establish standard...interconnection agreements

SDG&E, SCE and PG&E have each filed tariffs for interconnection agreements. With a few salient exceptions, the agreements are identical. For a complete description of variations between them, please see the Section 6 of the California Interconnection Guidebook.[31] SDG&E and SCE have the same set of agreements:

- Customer non-export ("Generating Facility Interconnection Agreement");
- Customer agreement for third-party installation and operation ("Customer Generation Agreement");
- Third-party non-export ("Generating Facility Interconnection Agreement (3rd Party Non-Exporting)").
- Customer inadvertent export ("Generating Facility Interconnection Agreement (Inadvertent Export)");
- Third-party inadvertent export ("Generating Facility Interconnection Agreement (3rd Party Inadvertent Export)").

[29] Distributed Power

[30] The Guideline is available at http://www.energy.ca.gov/distgen/interconnection/SUP_REVIEW_GUIDELINE.PDF.

[31] See Publication # 500-03-083F at URL http://www.energy.ca.gov/distgen/interconnection/guide_book.html.

The primary difference between the interconnection agreements of PG&E, when compared with the agreements of SCE and SDG&E, is that there is no accommodation for inadvertent export. Therefore, there is no customer inadvertent export agreement and there is no third party inadvertent export agreement. PG&E, then, has just the first three agreements listed above.

Point #6: Develop tools for utilities to assess...[DER]...on the grid

The FOCUS-II contract with the Energy Commission (#500-00-013) includes Task 2.2, "Select and Monitor twelve (12) DG projects". The scope of work document states:

> "The purpose of this task is to improve the cost-effectiveness of DG interconnection while maintaining the safety and reliability of the grid. This will be accomplished by gaining precise technical feedback on what effect interconnecting DG has on the local distribution grid. The FOCUS team will provide data, analysis and recommendations to the Energy Commission for its use and for the Interconnection Workgroup."

At present, 7 facilities with 14 distributed generators and two or more monitors per facility (PCC and DG)—19 monitors total—were selected according to the criteria outlined in the monitoring plan; instrumentation has been installed.

There are several reasons why this effort is judged here to have fulfilled 50% (rather than 100%) of the MC Action Plan point 6, requiring development of tools for utilities to assess DER. First, monitoring only 9 generators for harm to the grid will give utilities little additional confidence that the 10th generator will not cause problems. Second, Task 2.2 does demonstrate benefits to the distribution system of an interconnected generation resource. At this time, utilities have little confidence in real benefits to their distribution system with the presence of DG operating in parallel.

Task 2.2 of FOCUS-II nonetheless provides data on the behavior of DG on the grid where no data existed before. It has shown that 143 events (89 sags, 54 swells) came from the DG side and 193 events (130 sags, 63 swells) came from the PCC side. This is the first evidence yet that DG is having less impact on the grid than *vice versa*.

Point #7: Develop...regulatory principles compatible with [DER]

One of the regulatory "quiet revolutions" the Revised Rule 21 initiated was the idea of performance-based interconnection requirements (PBIRs). The old Rule 21—different for each of the three investor-owned utilities—prescribed and proscribed technological solutions to the challenges of safe and reliable interconnection of DG. The Revised Rule 21, on the other hand, sets performance-based standards and allows any technology to be used that meets those standards. This approach insures the safe and reliable operation of the grid *and* drives technological innovation. Each new interconnection equipment model requires Certification by a NRTL regardless of any certification of previous models. Certification would be simpler if a new uncertified model would be allowed to use a previously certified design as basis. PBIRs in Revised Rule 21 are described in detail in the FOCUS-I Final Report.[32] The objectives

[32] See "Objective 5: Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs)" in the FOCUS-I Final Report at: http://pier.saic.com/PDF/P600-01-006.pdf, February 2001, p24-39.

elaborated in the report includes 14 “principles compatible with DERs” enumerated in Section 1.1.

This Point #7 of the Action Plan is fulfilled for interconnection Rule 21. With the exception of Objective–14, where some discretion still exists, it is 100% fulfilled with the present effort.

Point #8: Adopt regulatory tariffs and utility incentives

The only tariffs considered in this report to impact interconnection cost effectiveness is the Revised Rule 21 (the interconnection tariff), so this point is 100% fulfilled.[33] Evidence of fulfillment is the completed Rule itself.

Point #9: Establish expedited dispute resolution processes

Section G of the Revised Rule 21 has a two-step process of dispute resolution, as described in Section 2.4.8.

Point #10: Define the conditions necessary for a right to interconnect

It is possible to consider that the Revised Rule 21 itself is the complete set of conditions necessary for a right to interconnect. This is true, at least insofar as the Rule encompasses all requirements for interconnection. It is safe to say that every provision of the Revised Rule 21 is meant to ensure the safety and reliability of the electrical system while allowing interconnection to proceed. The technical requirements in Section D are a particularly clear example of the efficacy of the performance-based interconnection requirements to establish limits that may be achieved as the market sees fit. By far the most compelling statement in favor of a *rationally pre*-determined *right* (as opposed to an *allowance arbitrarily* determined by fiat at the time) is this clause from Section B.1:

> “[The utility] shall apply this Rule in a non-discriminatory manner and shall not unreasonably withhold its permission for a Parallel Operation of Producer’s Generating Facility with [the utility’s] Distribution System.”

But the statement falls over easily: there is no universal standard of reasonableness. And although Section D is constructed to cover many technical situations, others arise that are not specifically defined. In special cases (and there is no limit to what may be determined a special case, given adequate technical reasons), the interconnection applicant has no recourse to the utility’s expertise and determination in its own favor.

It is possible, under the Revised Rule 21, for the utility to declare that *any* project requires a Detailed Study. The cost of the Study alone can discourage a customer sufficiently, especially a small customer so that it abandons the effort.

When the Revised Rule 21 first went into effect, it was difficult for the utilities to meet the 10-day timeline for Initial Review. There is anecdotal evidence that at least one of the utilities initially solved this problem by making an immediate determination that every project required a Detailed Study. This may be connected with the fact that a large number of projects were withdrawn in that utility’s service territory during the first year the Rule was in effect. The other utilities, meanwhile, met the commitment by declaring that the application was never

---

[33] Though many other tariffs impact *project* cost effectiveness, Rule 21 is considered most relevant to the cost of *interconnection*.

complete, and therefore the 10-day clock never officially started. The Working Group has had discussions on this point, attempting to gain a common understanding. The willingness of the utilities involved to cooperate—and not the provisions of Revised Rule 21—has allowed the Rule to attain its current success.

Yet despite the best intentions of the framers of the Revised Rule 21, the future success of the Rule is not assured because while the *right to interconnect* has been fairly well established, the opportunity for the utility to effectively bar certain interconnections through excessive requirements remains. Section B.1. above does require proof of reasonableness, though—a partial score for this point—considered here to be 50% fulfilled.

3.3.3.1 Simplified Interconnection Objective

Recall from the discussion in Section 0 here is no such thing as Supplemental Review or Initial Review in the Baseline. Any projects that passed only did so after Detailed Study. Many Baseline projects, as noted, did not pass at all. Therefore, we count progress toward the Simplified Interconnection Objective as a decrease in the number of projects not passing and, of those passing, an increase in the ones passing after Initial or Supplemental Review. In fact the Trendline under Revised Rule 21 shows dramatic improvement over the Baseline, as shown in Figure 3-3. In the Baseline (made up of MC projects), over 70% of projects required Detailed Study; the rest were withdrawn, suspended, or disconnected.[34] By sharp contrast, SDG&E has over 80% approval following Supplemental Review[35], almost 17% passing after Initial Review, and just 2% withdrawn. SCE has nearly as many projects passing after Initial Review as Supplemental Review and has only 1 Detailed Study. Over 10% of its projects are suspended, however.[36] PG&E actually shows more projects passing after Initial Review than those requiring Supplemental Review. After 3 years, however, about 35% of its project applications have been withdrawn and more than 10% have required Detailed Study.[37] Many of the projects withdrawing applications in PG&E territory withdrew during 2001 and 2002 when the program was in its early stages, so there appears to be a reduction of the withdrawal rate more recently. Exact distribution of PG&E interconnection status by years is unknown, since the company provided no breakout of data by year. Withdrawals occurred in PG&E territory as follows: 17 in 2001, 16 in 2002 and only 4 in the first three quarters of 2003.

One would expect a slightly higher occurrence of Detailed Studies in PG&E than in other utility territories because of the network distribution systems in the Bay Area.[38]

---

[34] Disconnections aren't shown here because there were none in the Trendline.

[35] Given the Initial Review requirements for the use of Certified Equipment and the relatively small but growing list of Certified Equipment, the low percentage of Simplified Interconnections is to be expected. Many of the Simplified Interconnections are likely passing by means of Interim utility approval.

[36] This includes only projects that are suspended and not resumed by the customer.

[37] This does not include projects not yet online.

[38] Network distribution systems require technical review beyond what's needed for radial systems.

FIGURE 3-3: SIMPLIFIED INTERCONNECTION PROGRESS

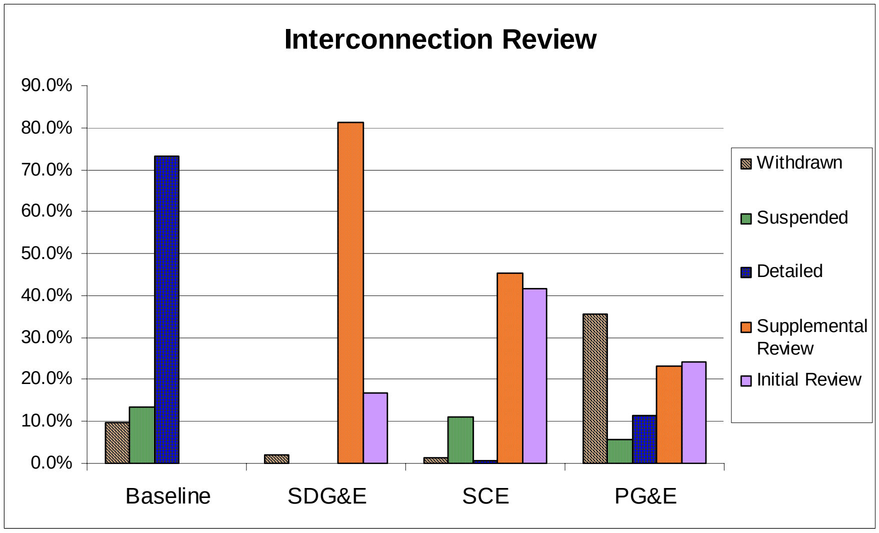
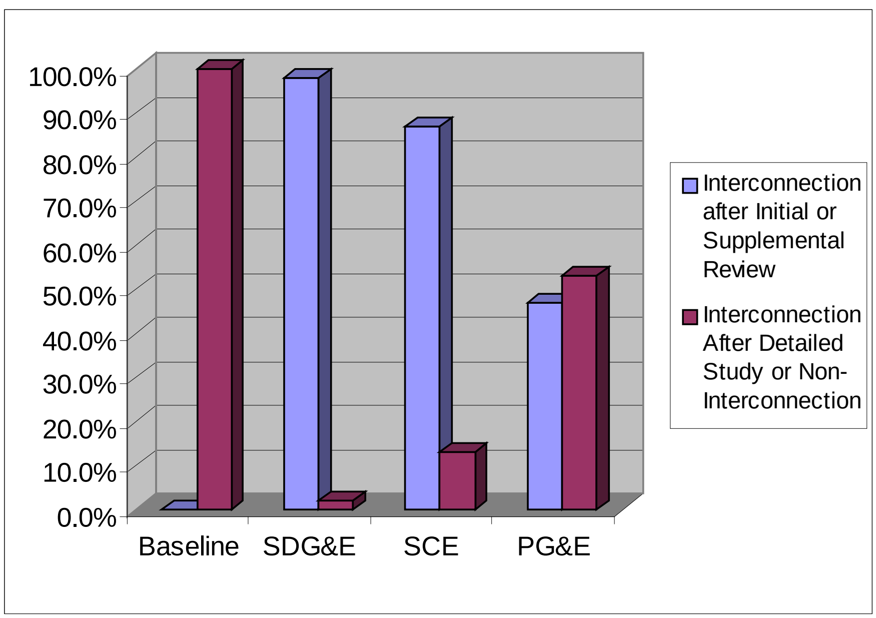


FIGURE 3-4: ALL UTILITIES INITIAL & SUPPLEMENTAL INTERCONNECTIONS VS. BASELINE



If we consider that acceptance of a given application following Initial or Supplemental Review signals success of Revised Rule 21 to progress toward the Simplified Interconnection Objective and that conversely withdrawal, suspension and Detailed Study signal failure, [39] then revised Rule 21 has been very successful.[40] Since the Revised Rule went into effect, roughly three out of

[39] Of course, any interconnection that is made is a success—even if it needs a Detailed Study; the point, though, is to contrast *progress* toward Simplified Interconnection.

[40] No NEM projects are included in this assessment.

four interconnections (74%) have been through Initial or Supplemental Review. Of the remaining interconnections, 14% were withdrawn, 7% were suspended, and 5% required Detailed Studies. Comparison of the IOUs' records for interconnection success shows:

- PG&E had 38 passing after Initial Review, 26 passing after Supplemental Review, and 19 Detailed Studies;
- SCE had 16 passing after Initial Review, 38 passing after Supplemental Review, and 1 Detailed Study;
- SDG&E had 8 passing after Initial Review, 39 passing after Supplemental Review, and 0 Detailed Studies.

3.3.4 Time Reduction Objective

3.3.4.1 Trendline Analysis

The amount of time to interconnect is not necessarily a direct reflection of utility interconnection practices—there are many causes of delays of customer projects. These may be delayed indefinitely or cancelled for reasons completely unrelated to interconnection. Improvements in interconnection times may not be solely attributable to improvements in utility interconnection handling procedures; they may also indicate the increasing intelligence by developers on how to apply and interconnect distributed resources. Furthermore, "delay" is inherently a subjective term. The "requested on-line" date is relative to the customer's expectation and may be therefore unreasonably short (for example, some applications list the day the application is handed in), or long (for example "sometime within the next 3 years"). The cost data are also relative to customer expectations and so must be treated with this limitation in mind. Yet, it may be said, it is getting easier and faster to interconnect in California under the Revised Rule 21.

- Communication among and between utilities and other stakeholders has improved;
- Utilities and third-party applicants have scaled the learning curve;
- Utilities now have staffing to handle DG applications from beginning to end;
- PG&E has a new Interconnection Services business unit to handle applications from their large and diverse service territory.

Year 2000 projects depicted below are in the CaIS Baseline. There are dramatic improvements in all utility territories.[41]

In SDG&E territory, average number of days to interconnect decreased by almost 50% two years in a row. Average days past requested on-line date decreased over the 4 years tracked by a total of 75%. Though PG&E had no interconnections in 2000, by 2003 it reduced average overall interconnection time to less than 60 days. Their

average interconnection time delay was negative in 2002, meaning that their average customer set expectations at a point later in time than the interconnection was delivered. In years 2001 and 2003, PG&E's time delay has been less than 25 days, best of the IOUs. Results for all utilities combined (Figure 3-8) are similar. The annual progress is remarkable and in large measure attributable to the changes introduced by Revised Rule 21.

FIGURE 3-6: SCE ANNUAL PROGRESS

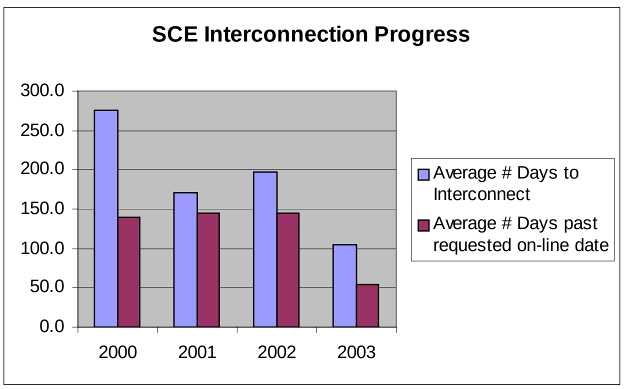


FIGURE 3-7: SDG&E ANNUAL PROGRESS

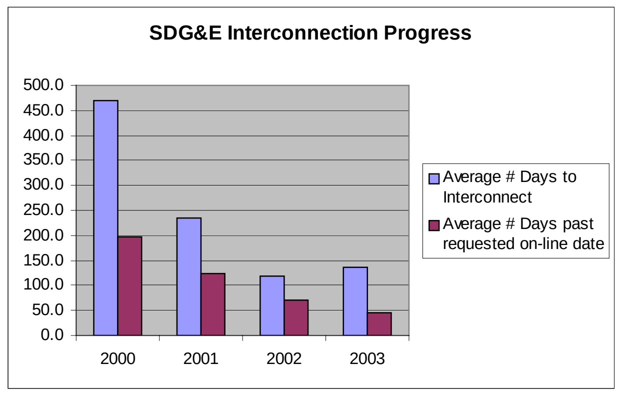
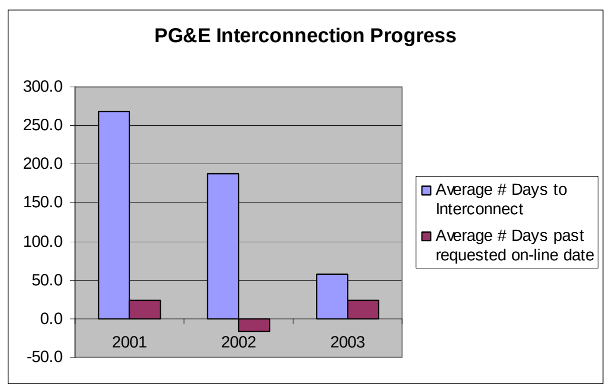


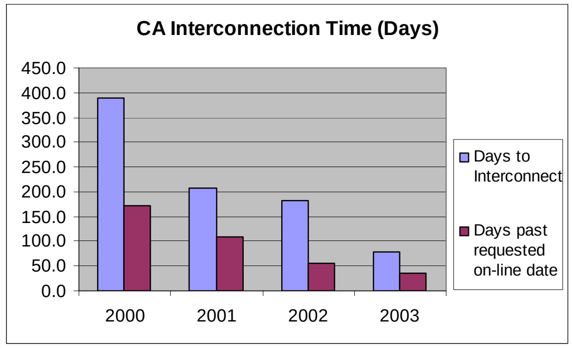
FIGURE 3-5: PG&E ANNUAL PROGRESS



[41] There is no written standard for exactly how the utilities should count times, however, which may explain some divergence in their results.

3.3.4.2 Trendline vs Baseline Comparison

FIGURE 3-8: CALIFORNIA ANNUAL PROGRESS



The Time Reduction Objective was to achieve a 20% decline in time to interconnect for units under 1MW. The Trendlines for units <1MW and for units 1MW and above for years 2001-2003 compared with the National, California and non-California Baselines.

The results show that the Time Reduction Objective of 20 percent is exceeded every year under the Revised Rule 21 by a large margin, no matter which Baseline is used. In fact, the time delay and overall time to interconnect projects larger than 1MW is also reduced by more than 20% every year as well. In 2001, total days to interconnect are reduced by 39% for projects less than 1MW, and by 61% for projects larger than 1MW. Time to interconnect in 2001 is reduced by 33% to 79% for projects less than 1MW, and by 22% to 62% for projects larger than 1MW. In 2002, total days to interconnect are reduced by 52% for projects less than 1MW, and by 53% for projects larger than 1MW. Time to interconnect in 2002 is reduced by 66% to 89% for projects less than 1MW, and by 61% to 85% for projects larger than 1MW. In 2003, total days to interconnect are reduced by 79% for projects less than 1MW, and by 82% for projects larger than 1MW. Time delays in 2003 are reduced by 78% to 93% for projects less than 1MW, and by 89% to 96% for projects larger than 1MW.

These numbers have a high degree of credibility, due to the credibility of the source (the IOUs) and sheer quantity of the data. Time reductions exceed the objective target and are the most direct measure of achievement of the Revised Rule 21.

3.3.4.3 Cost Reduction Objective

This analysis is constructed using only the cost reduction Baseline projects treated as if Revised Rule 21 were in effect, to gauge whether cost reductions would result. This is a judgment made with only partial interconnection information since no detailed site information is available. Where no explanation for cost data is available in the Making Connections report, the project is removed from the Trendline. NEM projects are eliminated. After following this procedure for each of the cost reduction Baseline projects,[42] four projects are left. A description follows of the cost reductions available under Revised Rule 21 for each of these projects.

Of the projects from MC with identifiable cost reductions under Revised Rule 21, 1 is in California, 3 are in other states. All are less than 1MW. The lack of data on projects over 1MW makes Cost Reduction Objective results in this size range unavailable. As projects become larger (especially as a ratio to existing electric distribution system circuit capacity), they often require more utility study and are more likely to require facility or distribution system upgrades. These costs may be more attributable to the location of the DG involved than they are to the utility interconnection regulations, so that costs become less easily attributed to the revisions of

[42] From Making Connections only, the CaIS projects having been excluded already.

Rule 21. Having no cost data for larger projects further reduces the certainty of conclusions in this size category.

High cost for MC projects is relative, as mentioned previously. That means some costs are expected by the customer, and not considered to be excessive; others are not expected and appear to be excessive because they do not fit any expectation. Though relative cost data makes conclusions less certain, it is possible to complete the analysis by isolating the technical requirement in the MC project, then determining whether revised Rule 21 has the same requirement or not. If so, the cost under Revised Rule 21 is computed; if not, the cost becomes $0. All costs normally associated with interconnections passing with Simplified Interconnection or Supplemental Review are considered "expected"; Detailed Study costs are considered "unexpected"—since they were the prevailing condition before Rule 21, and are used today only when Initial and Supplemental review fail to solve the interconnection issues under normal utility review.   The expectations assume a customer that is technically astute but not conversant with Rule 21.

Expected costs will include:

- Protection at the PCC (for each meter);
- Utility charge for the commissioning test.
- Interconnection study cost;
- Net Generation Output Meter (for each meter);[43]

Unexpected costs include:

- Detailed Study additional equipment and engineering.
- Redundant protection requirements for over/under voltage and over/under frequency;[44]

Reconstructing the costs for the following projects is a four-step process:

1. Compare the cost overrun issue as reported in MC;
2. Determine the cost under revised Rule 21;
3. Determine whether there are any "unexpected costs;
4. Total the cost savings or increase.

[43] NGOM is not required by Rule 21, but by other utility tariffs.

[44] This has been required in some field situations by utilities in California—post Revised Rule 21.

In most cases, Revised Rule 21 eliminates 100% of what MC calls the "barrier related cost".

TABLE 3-7: ESTIMATED TRENDLINE INTERCONNECTION COSTS

		Simplified Interconnection	***Supplemental Review Interconnection***	***Detailed Study Interconnection***
Interconnection Study	*Cumulative Cost*	$800	$1,400	$8,900
Protection at PCC ($ per Meter)	*Hardware*	$0	$3,000	$3,000
	Labor	$0	$9,000	$9,000
Redundant Anti-Islanding Protection ($ per Meter)	*Hardware*	$0	$0	$1,500
	Labor	$0	$0	$1,000
Net Generation Output Meter ($ per Meter)		$0	$5,000	$5,000
Additional Requirements	*Equipment & Engineering*	$0	$0	$59,500
Commissioning Testing	*Customer/Vendor Pre-test*	$5,000	$7,500	$7,500
	Commissioning test	$3,000	$5,000	$5,000
TOTAL		$8,800	$30,900	$100,400

NOTE: All costs are engineering estimates only, not actual costs. Not all interconnection costs are depicted; actual costs will vary.

MC Case Studies

Example MC Case #15—75kW Microturbine in California

Developers of this project reported that the utility told them they had no obligation to interconnect them and wouldn't be able to because they were not a Qualifying Facility as defined under PURPA.[45] Later, the utility agreed to attempt the interconnection under an "experimental" or "test" interconnection agreement.[46] The utility indicated that it would require the project

[45] Public Utility Regulatory Policy Act of 1978.

[46] "Making Connections", p. 64.

developer to pay for a "method of service study required for all...facilities except [Net Energy Metered] projects." The utility indicated that this could cost up to $50,000 and take six months to perform; they also said the study cost was "non-negotiable" and that if the developer didn't pay, it would have to abandon the project.[47] Therefore, the developer added a projected cost overrun of $50,000 to the budget.

No 75kW microturbines are certified (at this date), so this project would not qualify for Simplified Interconnection. It is *not* likely that a Detailed Study would be required for a non-exporting project of this size. The study cost, then, would be for Supplemental Review. A technically astute customer would expect to pay for a protective device at the PCC, and would expect a utility commissioning test prior to permission to run.

Revised Rule 21 eliminates 100% of this barrier-related cost.

Baseline (MC) costs

Original MC cost (for interconnection study) = $50,000;

Revised Rule 21 costs

Estimated Rule 21 cost (for interconnection study) = $1,400

Cost Reduction due to Revised Rule 21 = $48,600

Expected Costs

Expected protection at the PCC = $12,000

Expected utility commissioning test = $5,000

Study costs (Supplemental) = $1,400

Net Generation Output Meter = $5,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

None

Total cost savings under Revised Rule 21 = $48,600 = 97% reduction

Example MC Case #14—120kW Propane Gas IC Engine

As in other Baseline projects mentioned above, the utility in this case was asking for extra protection, beyond what the manufacturer of the generator had already provided. "The utility required synchronizing equipment and parallel operation monitoring for the induction generator

[47] Same as above.

that has a reverse power relay installed [already] that shuts down the entire cogeneration plant. This cost was $7,000[48] for equipment that the developer argued was unneeded."[49]

Revised Rule 21 requires protection at the PCC, but is silent on the requirement for redundant reverse power protection. To the extent that reverse-power and other interconnection functions are provided by the manufacturer protection package, the utility, at its discretion, can allow those functions to serve as reverse power protection or it may require redundant protection. Allowing the manufacturer protection to suffice does not presuppose that the utility accepts the functionality of the manufacturer's protection package. There are new options in Revised Rule 21 for the utility to satisfy itself, other than simply requiring additional protection:

- The interconnection device can be Certified by a NRTL;
- The interconnection device can receive interim certification from the utility;
- The utility can do field tests to satisfy itself.

Only four IC engines (from a single manufacturer) are currently Rule 21-Certified, and all are smaller than 100kW. It is reasonable to assume that the IC engine in this example isn't Rule 21-Certified, so the interconnection would require Supplemental Review.

Redundant protection cost is estimated at $3,500. Under Revised Rule 21, synchronizing equipment (estimated at $7,000 - $3,500 = $3,500) is not required, reducing that portion of the interconnection cost.

Baseline (MC) costs

Original MC cost for synchronizing equipment and reverse power relay = $7,000

Revised Rule 21 costs

Estimated cost:

For synchronizing equipment = $0

For redundant reverse power relay = $3,500 (may be required)

Expected Costs

Expected protection at the PCC = $12,000

Expected utility commissioning test = $5,000

Study costs (Supplemental) = $1,400

Net Generation Output Meter = $5,000

Customer/Vendor pre-test = $7,500

[48] The figure of $7,000 is used as the total "barrier-related cost".

[49] "Making Connections", p. 62.

Unexpected Costs

For redundant reverse power relay = $3,500 (may be required)

Total cost savings under Revised Rule 21 = $3500 = 50% reduction

Example MC Case #12—140-kW Gas IC Engine

The issue in this case was power factor. MC states, "The utility initially required the customer to bring the total facility power factor up to .90 from an average of .86—this would have required the customer to install capacitor banks, or capacitors on many of its inductive loads in the building to correct the power factor. ... In the opinion of the project manager, the requirement should be for the generators to supply their fair share of the VARs, and no more."

The technical solution provided to this problem under the Revised Rule 21 is in Section D2f:

> **Power Factor.** Each Generator in a Generating Facility shall be capable of operating at some point within a power factor range of 0.9 leading to 0.9 lagging. Operation outside this range is acceptable provided the reactive power of the Generating Facility is used to meet the reactive power needs of the Host Loads or that reactive power is otherwise provided under tariff by Electrical Corporation. The Producer shall notify Electrical Corporation if it is using the Generating Facility for power factor correction.

Under the Revised Rule 21, the customer can advise the utility that it will use the generator to provide all, or a portion of, the reactive power required to bring the facility power factor up to 0.9 lagging. This may require active control of the generator's reactive power output to maintain a 0.9 value at the PCC. MC states, "The installation ultimately resulted in an additional charge of $3000 for equipment that was considered redundant and a $2000 equipment testing charge that was considered unnecessary." Under Revised Rule 21, these charges may have been eliminated. The project would require Supplemental Review, however.

Because Rule 21 explicitly gives options to power factor correction, that cost may be waived.

Baseline (MC) costs

Original MC cost = $3000;

Additional cost = $2,000

Total cost overrun for power factor correction = $5,000

Revised Rule 21 costs

Rule 21 cost for power factor correction = $0

Expected Costs

Expected protection at the PCC = $12,000

Expected utility commissioning test = $5,000

Study costs (Supplemental) = $1,400

Net Generation Output Meter = $5,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

None

Total cost savings under Revised Rule 21 = $5,000 = 100% reduction

Example MC Case #9—703-kW Steam Turbine in Maryland

As with many of the MC examples, this project met significant resistance from the utility and from the whole interconnection environment, including:

- The customer paid for a utility study that the utility then discarded;
- The customer fulfilled the utility technical requirements, only to have a new set of technical requirements added on;
- The utility demanded to have operational control of the generator;
- The project experienced two years (and counting) of delay;
- No utility point person was established;
- No dispute resolution process was available;
- There was no PUC support for dispute resolution in the case;
- There was no technical procedure for dealing with networks.

All of these issues, it may be safely stated, have been successfully handled in the procedures of the Revised Rule 21—except the last. There is no clear technical approach at this date for handling network interconnection. It is still a costly and unclear procedure. This fact has a significant bearing on the outcome of the cost effectiveness of the project, as will be shown.

Revised Rule 21 does have an Initial Review screen that requires all DG projects located on a network to undergo a Supplemental Review. At this time there is no technical guide for Supplemental Review for networks. "The direct costs incurred in meeting the interconnection standards were $88,000." Additionally, "...the project owner paid for $44,000 in fees incurred by consultants for the utility to design the requested network protection. Upon completion, the utility expressed dissatisfaction with the result, and started [over]." [50] It is unclear whether this is equivalent to a "Detailed Study"—but, in any case, it is unlikely that an interconnection today that would be subject to the cost for an unused study. One other fact is necessary to this cost

[50] Both quotes from "Making Connections", p. 54.

reconstruction: “...the building is served by three 13.8-kV distribution feeders.” This is interpreted to mean that the building had three utility services, tripling some protection costs.

Baseline (MC) costs

Original cost overrun (MC)= $88,000

Additional cost (MC) = $44,000

Total cost overrun (MC) = $132,000

Revised Rule 21 costs

Estimated Rule 21 cost = $59,500 + $7,500 = 67,000 (See Table 3-7.)

Expected Costs

Expected protection at the PCC = $12,000 x 3 = $36,000

Expected utility commissioning test = $5,000

Study costs (Supplemental and Initial) = $1,400

Redundancy protection = $2,500 x 3 = $7,500

Net Generation Output Meter = $5,000 x 3 = $15,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

Study costs (Detailed) = $7,500

Estimated network protection equipment & engineering = $59,500

Revised Cost overrun = $67,000

Total cost savings under Revised Rule 21 = $67,000 = 49% reduction

3.3.4.4 Trendline Summary

It is possible to gain further insight into the end-user interconnection cost effectiveness Trendline by summarizing the above results. All four cases produce positive savings in the Trendline over the Baseline. A weighted average of the cost savings of these projects shows an end-user cost savings of 74%. This meets the Cost Reduction Objective for projects <1MW (30%), and exceeds it by 44%. Assuming similar results for units 1MW+, the above exceeds the Cost

Reduction Objective for projects 1MW+ by 59%. From the view of these reconstructed interconnection costs to the end-user, the Cost Reduction Objective is met.

4 Conclusions and Recommendations

4.1 Conclusions

4.1.1 Specification Conclusions

Even though the work was completed, the goal of electronic applications and processing was not achieved. The process was deemed just too complicated to handle with electronic submittals at this time. However, Rule 21, applications, and other information are available from utility and Energy Commission websites.

4.1.2 Monitoring Project Conclusions

The following conclusions may be made for the data analyzed from the FOCUS-II monitoring project:

- For the systems monitored, the impact of the DG upon the grid power quality was found to be very low. The impact of the grid upon DG was also very low. This was determined by comparing the impact with previous studies. While the sample was too small and the duration too short for a general conclusion, it provides some assurance that the current requirements and approval process for DG is conservative, and is adequately protecting the grid. Some of the bullets below elaborate on this finding.
- The project approach of placing a minimum of two monitors at each site—one at the DG, and one on the utility side of the PCC—has yielded a significant advantage: it has made it possible to measure how many events originate on the distribution system and are propagated to the DG on the customer site and how many events originate at the customer site with DG and are propagated to the distribution system. It is therefore possible, based on this sample, to conclude about the relative effects the parallel systems (DG & distribution system) are having on each other.
- A total of 336 events were logged during the monitoring. Of these, there are 143 SARFI events originating on the DG side (89 Sags & 54 Swells); 193 SARFI events originating on the PCC (Utility) side (130 Sags & 63 Swells), distributed as follows:

Project	DG Sag Events	PCC Sag Events	DG Swell Events	PCC Swell Events
Irvine - Total	10	16	0	0
Los Angeles - Total	11	3	9	0
Redlands - Total	28	46	0	0
San Diego - Total	4	20	44	63
South Gate - Total	25	21	1	0
Sunnyvale - Total	11	24	0	0
All Facilities - TOTAL	89	130	54	63

None of these events (save one, see below) was of serious consequence.

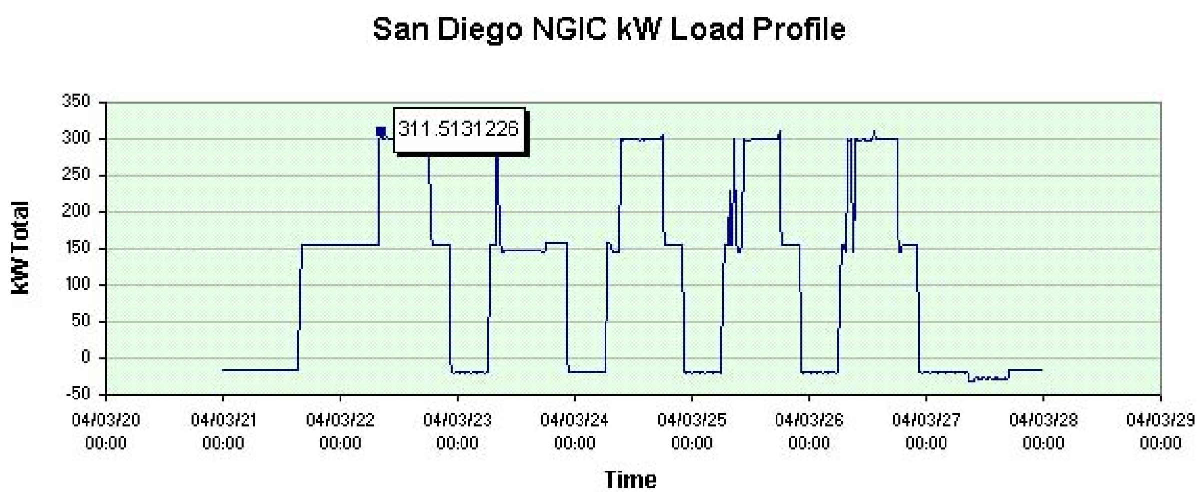
- In the FOCUS-II sample of projects, it is clear from the above that, on average, 50% more events originate on the PCC (Utility) side than on the DG side. Southgate and Los Angeles are exceptions. If the FOCUS-II Monitoring Project is representative of DG installations in the state, it may be said that in general DG is having less effect on the grid than the grid is having on DG. The impact in either direction, however, is not very significant. The most significant power quality events recorded were natural phenomena: the lighting strike at the Los Angeles facility and the fires near Redlands and San Diego.
- There has been only one incidence of an interruption (voltage reduction greater than 90%)—at Redlands on 11/25/02 at 13:28:34, the voltage on the PCC side dropped to 9% pu for 0.734 sec. This is classified as a "momentary" event under IEEE 1159-1995. Because the voltage never dropped to 0%, and no temporary or long duration interruptions occurred, it is not possible to report any condition of "islanding",[51] or about the effectiveness of anti-islanding protection.
- The power quality monitors installed throughout California as part of project demonstrated a high level of availability with an average availability of over 99% from 8/26/02 to 4/30/04.
- The frequency of events at the PCC was about one-third of the benchmarks created by EPRI and Edison. The average FOCUS-II PCC monitor experienced about 15.47 voltage sags and interruptions per 365 days. The average measured by EPRI's DPQ Project survey of 24 electric utility systems was about 54.63 voltage sags and interruptions. The average Edison service entrance monitor also experienced about 47.42 voltage sags per 365 days. The IEEE standard for such events is IEEE Std. 1159-1995 which defines monitoring of electric power quality of ac power systems, definitions of power quality terminology, impact of poor power quality on utility and customer equipment, and the measurement of electromagnetic phenomena are covered. IEEE standard 1366-2003 defines useful distribution reliability indices, and factors that affect their calculation, are also identified. This standard includes indices that are used today as well as ones that may be useful in the future.
- The frequency of events at the DG was about half those at the PCC. The average FOCUS-II DG monitor experienced about 7.25 voltage sags and interruptions per 365 days.
- The frequency of severe events was also low compared to the benchmark. The rate of very severe voltage sags and interruptions at the PCC was 0.59 events while the DG was 0.14 per 365 days (considering those voltage sags with voltage magnitudes below 0.50 per unit). For comparison, the severe $SARFI_{50}$ event frequency was 4.93 events in the SCE DPQ Study while the EPRI DPQ Study found a feeder average of 12.07 events per 365 days.

---

[51] Rule 21 defines Islanding as "A condition on [the utility's] Distribution System in which one or more Generating Facilities deliver power to Customers using a portion of [the utility's] Distribution System that is electrically isolated from the remainder of [the utility's] Distribution System."

- The average value of voltage total harmonic distortion (THD_V) measured at the PCC was 1.35% and DG was 1.41% well with in the IEEE Std. 519-1992 requirements.
- All of the Power Quality Indices were lower than the EPRI's and Edison DPQ Projects indicating that the DG is not introducing any unwanted power quality events into the distribution system.
- Only the Irvine site with a Fuel Cell exported power and all power quality indices for that site were well within the Monitoring Project nominal values. This provides some comfort that exporting of small amounts of power may be acceptable, although much more data would be needed to provide assurance of this. Net Metering systems also allow minor export of power, and no serious consequences of such export have been reported.
- We found that DG is installed for various reasons and this dictates the operating mode. For instances, the San Diego site which is a commercial building has a program cycle for its two ICs. This site has two natural gas-fired Hess IC engines that cycle on and off based on a time-of-day schedule (Figure 7-1). The facility site has experienced many swell events that occur during periods of startup of the IC engines but the majority of these events are recorded by the PCC monitor first and then the DG monitor. These events appear to be occurring on the distribution system and by review of the individual events; it is found that they occur late afternoon. This condition may be cycling of capacitor banks for voltage control on the feeder.

FIGURE 4-1: TYPICAL DAILY LOAD PROFILE FOR SAN DIEGO NGIC



4.1.3 Streamlining Rule 21 Conclusions

The streamlining of Rule 21 has produced some very positive results. The following conclusions are drawn from the Outcomes of Rule 21 streamlining effort:

Process Improvements

- The process of interconnection has been improved by 83% over the "Making Connections" baseline.

The Time Reduction Objective of 20 percent is exceeded every year under the Revised Rule 21 by a large margin, no matter which Baseline is used. Figure 4-2 shows that the objective has been achieved every year for units <1MW;

- Figure 4-3 shows it has been achieved every year for units 1MW+.

FIGURE 4-2: TIME DELAY TRENDLINE (ALL CA IOUS) VS BASELINE UNITS <1MW

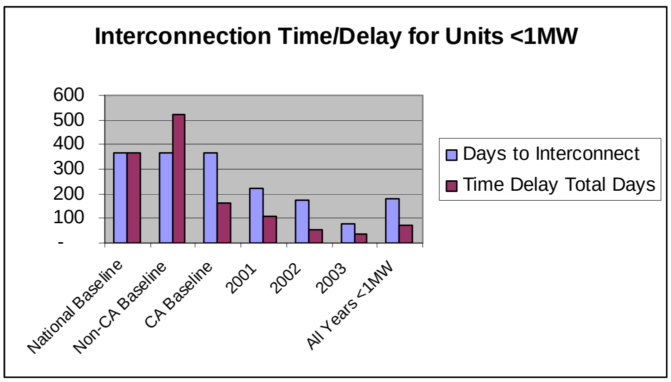
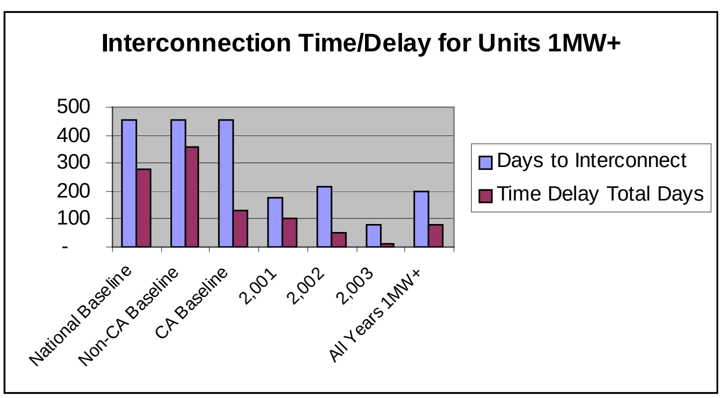


FIGURE 4-3: TIME DELAY TRENDLINE (ALL CA IOUS) VS BASELINE UNITS 1MW+



Certification of DG Systems

The following interconnection technologies have been Certified under Rule 21:

- Capstone Turbine
  - Model 330, 30 kW Microturbine Generator
  - Model 60, 60 kW Microturbine Generator
- Fuel Cell Energy
  - Model DFC300A-S, (Using a UL-Listed, SatCon Power Systems Canada, Ltd Model AE-462-60-F-A Inverter)
  - Model DFC1500, 1000 kW Direct Fuel Cell (DFC) Power plant
- Plug Power
  - Model SU1PCM-059622, 5 kW Fuel Cell
- Tecogen
  - Model CM60H, 60 kW Induction Generator
  - Model CM60L, 60 kW Induction Generator
  - Model CM75H, 75 kW Induction Generator
  - Model CM75L, 75 kW Induction Generator

Cost Reduction

TABLE 4-1: SUMMARY OF TRENDLINE END-USER COST SAVINGS

Case #	Technology	kW	MC Cost Overrun	Cost Under Rule 21	MC Cost Overrun $/kW	Total Cost Savings	Cost Savings $/kW	Percent of Cost Reduction
Case #15	NGMT	75	$50,000	$1,400	$667	$48,600	$648	97%
Case #14	Propane IC	120	$7,000	$3,500	$58	$3,500	$29	50%
Case #12	NGIC	140	$5,000	$0	$36	$5,000	$36	100%
Case #9	Steam turbine	703	$132,000	$67,000	$188	$65,000	$92	49%
Statewide average							**$201**	**74%**

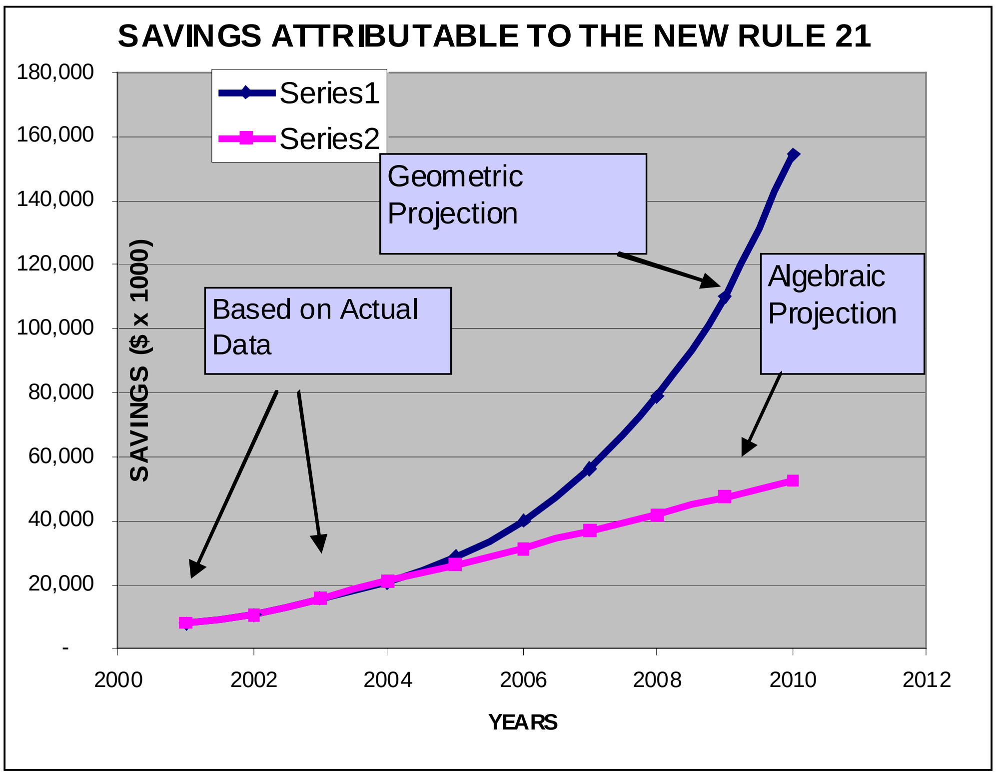
- The Cost Reduction Objective has been exceeded. The weighted average of the cost savings of the projects analyzed shows an end-user cost savings of 74%. This exceeds the target of 30%.
- The costs associated with delays in interconnection approval and installation have been reduced by more than 20% for projects of all sizes. The aggregate savings attributable to the streamlining is over $34 million for the three years considered. Savings were estimated to be $26 million for units over 1 MW and $8 million for units below 1 MW. Projected savings into the future would be similarly large.

Commercialization Potential

The FOCUS-II Interconnection project was not designed to yield a new technology. Rather, the purpose of this program is to make utilization of DG easier by reducing cost and time to interconnect. Commercialization, then, refers to:

- Increased possibilities of DG being commercially viable because of reduced barriers interconnection; and
- The commercial benefits attributable to the Revised Rule 21, as shown in Figure 4-4.

FIGURE 4-4: PROJECTED SAVINGS FROM REVISED RULE 21



4.2 Conclusions and Recommendations

This project, along with the efforts of many others, has helped streamline interconnections significantly. As one measure of success, the time frame for interconnections has dropped significantly even as DG applications are on the rise.

The collaborative, consensus-building approach through the Working Group has helped improve communication, resolve technical issues, and has resulted in a greater appreciation by stakeholders of each other's problems.

DG is becoming more complex, driven by high energy prices, a need for more reliable energy, energy dependency issues, a desire for clean and renewable energy, and waste disposal issues. There is a continuing need for collaborative resolution of thorny issues. It is recommended that the Working Group continue meeting, perhaps less frequently as the incidence of new issues declines.

California stakeholders should continue to work with the IEEE to keep communications open and cross-fertilize.

The monitoring program found no significant impact of DG, and only one instance of an impact of the grid on DG, caused by a lightning strike. It is recommended that the DG monitoring program be enlarged to monitor more complex sites, and the duration of the monitoring be expanded. It is recommended that other DG monitoring efforts be undertaken. FOCUS-III will begin this effort.

The project has been worth pursuing. The payback is already large, and promises to be even larger.

GLOSSARY

ac.......alternating current
ASD.......adjustable speed drive
CBEMA.......Computer Business Equipment Manufacturers Association
CHP.......combine heat & power
CT.......current transformer
dc.......direct current
DG.......Distributed Generation
DIC.......diesel internal combustion
DPQ.......distribution power quality
EI.......Edison International
EPRI.......Electric Power Research Institute
FC.......fuel cell
FFT.......Fast Fourier Transform
Hz.......Hertz
IEC.......International Electrotechnical Commission
IEEE.......Institute of Electrical and Electronics Engineers
ITIC.......Information Technology Industry Council
kA.......kilo-amperes (1000 amperes)
kV.......kilo-volts (1000 volts)
kVA.......kilo-volt-ampere (1000 amps)
kVAR.......kilo-var (1000 var)
kW.......kilowatts (1000 watts)
kWh.......kilowatt hour (1000 watt hours)
LADWP.......Los Angeles Department of Water & Power
MCT.......methane combustion turbine
MIC.......methane internal combustion
mK.......mega-watts (1000000 watts)
MMT.......methane microturbine
NGCT.......natural gas combustion turbine
NGFC.......natural gas fuel cell
NGIC.......natural gas internal combustion
NGMT.......natural gas microturbine
PC.......personal computer
PCC.......point of common coupling

PG&E .... Pacific Gas & Electric
PLC .... programmable logic controller
PQ .... power quality
PT .... potential transformer
pu .... per unit
PV .... photovoltaic
RMS .... root mean square
SARFI .... System Average rms (Variation) Frequency Index
SCE .... Southern California Edison
SDG&E .... San Diego Gas & Electric
SEMI .... Semiconductor Industry Council
SMUD .... Sacramento Municipal Utility District
TDD .... total demand distortion
THD .... total harmonic distortion
UPS .... uninterruptible power supply
VAR .... unit of reactive power (reactive volt-ampere)

APPENDIX A: LINKS TO FOCUS-II INTERCONNECTION REPORTS

Monitoring Program Final Report:

[Pending California Energy Commission posting; check http://www.energy.ca.gov/.]

Making Better Connections:

[Pending California Energy Commission posting; check http://www.energy.ca.gov/.]

California Interconnection Guidebook:

http://www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF

ATTACHMENT A: WEBSITES AND REFERENCES

California Energy Commission General Website:

http://www.energy.ca.gov/

California Energy Commission DG Website:

http://www.energy.ca.gov/distgen/

California Interconnection Rule 21:

At SCE: http://www.sce.com/NR/sc3/tm2/pdf/Rule21.pdf

At SDG&E: http://www.sdge.com/tm2/pdf/ERULE21.pdf

At PG&E:
http://www.pge.com/docs/pdfs/suppliers_purchasing/new_generator/retail_generators/ER21.pdf

FOCUS-II Power Quality Monitoring Project:

www.dgmonitors.com (live monitoring information)